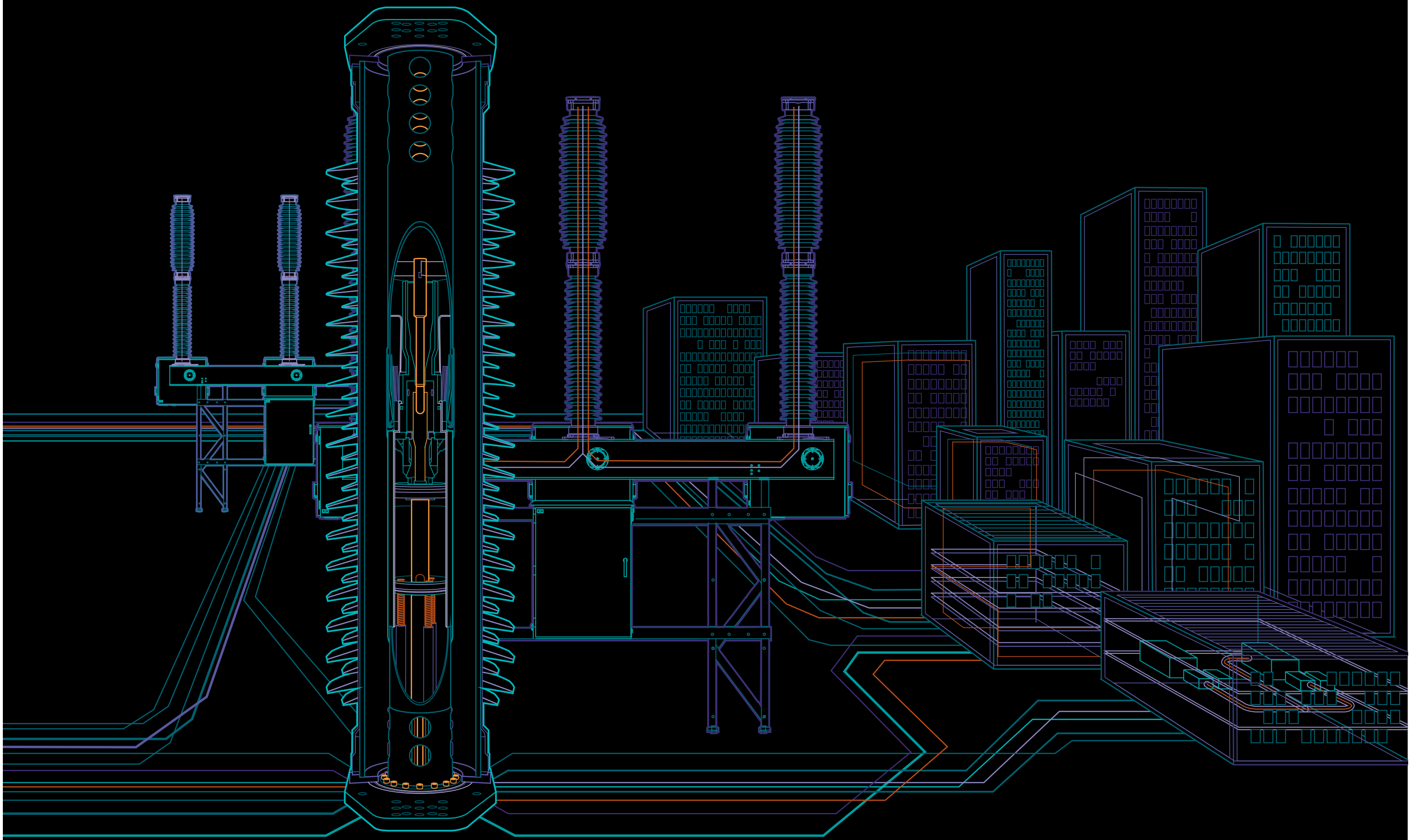

Live Tank Circuit Breakers
Application Guide

Power and productivity
for a better world™

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Scope

This document gives background information for selection of the best possible circuit breaker solution for each particular application.

The guide addresses utility, consultant and project engineers who specify and apply high-voltage circuit breakers.

The guide addresses live tank circuit breakers in general for voltages up to 800 kV.

The most usual requirements on a circuit breaker are mentioned, such as the capabilities to handle network stresses, insulation levels, mechanical forces and ambient conditions.

The construction of circuit breaker poles and operating mechanisms will be mentioned only briefly since these parts are described in ABB Buyer's Guide for Live Tank Circuit Breakers.

1. Introduction

1.1 What is a circuit breaker?

A circuit breaker is an apparatus in electrical systems that has the capability to, in the shortest possible time, switch from being an ideal conductor to an ideal insulator and vice versa.

Furthermore, the circuit breaker should be able to fulfill the following requirements:

1. In the stationary closed position, conduct its rated current without producing impermissible heat rise in any of its components.

2. In its stationary positions, open as well as closed, the circuit breaker must be able to withstand any type of overvoltages within its rating.

3. The circuit breaker shall, at its rated voltage, be able to make and break any possible current within its rating, without becoming unsuitable for further operation.

The requirements on live tank circuit breakers may be as high as 80 kA current interrupting capability and 800 kV rated voltage.

In addition to live tank circuit breakers, there are also other constructions of the circuit breaker poles (dead tank, GIS).

In earlier times, oil and compressed air were typical insulating and extinguishing medium. Nowadays they are almost entirely replaced by SF_6 gas for economical and practical reasons, and also due to increased demands for higher ratings.

There are different types of operating mechanisms, e.g. spring-, hydraulic- and pneumatic-operated mechanisms, and recently digitally-controlled motors have come into use.

Figure 1.1 Circuit breaker for 145 kV

Figure 1.2 Circuit breaker for 420 kV

1.2 Why do we need circuit breakers?

The circuit breaker is a crucial component in the substation, where it is used for coupling of busbars, transformers, transmission lines, etc.

The most important task of a circuit breaker is to interrupt fault currents and thus protect electric and electronic equipment.

The interruption and the subsequent reconnection should be carried out in such a way that normal operation of the network is quickly restored, in order to maintain system stability.

In addition to the protective function, the circuit breakers are also applied for intentional switching such as energizing and de-energizing of shunt reactors and capacitor banks.

For maintenance or repair of electrical equipment and transmission lines, the circuit breakers, together with the disconnectors, earthing switches or disconnecting circuit breakers with built-in disconnecting function, will ensure personnel safety.

1.3 Different types of switching

The requirement to switch any current within the circuit breaker's rating includes different making and breaking conditions:

- Terminal faults, short-circuits in the vicinity of or near the circuit breaker.
- Short-line faults, short-circuits to ground along the transmission line within a few kilometers of the circuit breaker.
- Out-of-phase conditions at which different parts of the network are out of synchronism.
- Intentional switching of capacitor banks, shunt reactor banks, no-load transformers, no-load lines and cables. In this connection controlled switching ought to be mentioned. This is described in ABB Controlled Switching, Buyer's and Application Guide.

The different switching conditions will be explained in Section 3, Current switching and network stresses.

1.4 Disconnecting and withdrawable circuit breakers

It has been mentioned that the circuit breaker is an important element in the system, either as a ”stand-alone circuit breaker” in a conventional substation or as an integrated part of a compact switchgear assembly.

The modern solutions with Disconnecting Circuit Breakers (DCB) and Withdrawable Circuit Breakers (WCB) make it possible to develop new types of switchgear constructions.

The purpose of the compact switchgear assembly is to simplify the switchgear and at the same time to improve the reliability of the system.

The different types of compact switchgears have one thing in common elimination of the conventional disconnectors in the system. Disconnectors have basically the same failure rate as circuit breakers, but need more frequent maintenance.

The DCB is a circuit breaker that satisfies the requirements for a circuit breaker as well as a disconnector. This is described in IEC 62271-108.

Ratings for current and voltage are the same as for a circuit breaker, while the insulating levels comply with those for disconnectors. Disconnecting circuit breakers are normally combined with remotely-operated earthing switches and interlocking systems to provide increased safety. A DCB for rated voltage 145 kV is shown in Figure 1.3.

In the WCB, the circuit breaker poles are mounted on a movable trolley and provided with additional contacts for the disconnector function. The movement of the trolley replaces the close/open function of the conventional disconnectors. See Figure 1.4.

A WCB can be extended with a complete gantry and busbars. It is even possible to equip the WCB with current transformers or earthing switches.

Availability studies have shown that in substations with DCB or WCB, the availability is considerably improved over that of conventional solutions. In addition to the low failure rate and long periods between maintenance, another advantage is the substantial reduction in space.

Figure 1.3
Disconnecting Circuit Breaker (DCB) for 145 kV.
The earthing switch is painted in red and yellow.

Figure 1.4
Withdrawable Circuit Breaker (WCB)
for 145 kV with busbars and gantry.

1.5 Circuit switcher

The circuit switcher is a lighter “economy variant” of the live tank circuit breaker.

The construction is similar and it can be applied for interruption of short-circuit currents, protection and switching of capacitor- and reactor-banks, transformers, lines and cables in accordance with IEC and IEEE/ANSI standards. The fault clearing rating is somewhat lower than that of the corresponding circuit breaker, and the operating times are longer.

IEEE C37.016 specifies the requirements for circuit switches.

1.6 Environmental aspects

Circuit breakers are installed in all kinds of environments and must be able to withstand and operate in any type of climatic conditions, such as extreme high and low temperatures, high humidity, ice loads and high wind velocities.

Other important requirements are the capability to withstand seismic activity and to maintain correct function in areas with high pollution as well as in installations at high altitudes.

2. Live tank circuit breaker designs and operating principles

2.1 Historical development

The air blast circuit breakers, which used compressed air as the extinguishing medium, had the advantage of high interrupting capability and short interruption times. However, the breaking units (interrupters) had limited dielectric withstand capability and, as can be seen in Figure 2.1, a circuit breaker for 420 kV needed up to 10 breaking elements in series per phase. The arc extinction required high air pressure, around 2 MPa, which meant that the risk of leakage was high. Installation, maintenance and repair were costly.

Air blast

Oil

SF_6 gas

Figure 2.1 The historical development of ABB live tank circuit breakers

Introduction of the minimum oil circuit breakers around 1970 was a big step forward. The number of breaking units was reduced; a circuit breaker for 420 kV needed only four interrupters in series per phase. The demand of energy for operation was relatively low, and spring-charged mechanisms could be used. Both the minimum oil circuit breaker and the spring mechanisms are practically unaffected by the ambient temperature. Another great advantage is that all maintenance, even opening of the breaking units, can be carried out outdoors. However, although the maintenance is relatively simple, certain switching operations (e.g. switching of small inductive currents) require rather frequent maintenance.

SF_6 gas circuit breakers are superior to these earlier technologies as they require substantially less maintenance. Furthermore, the numbers of breaking units are reduced. Up to 300 kV one interrupter per phase is used, and at 550 kV only two interrupters are required. All ABB SF_6 live tank circuit breakers can be operated with spring-charged mechanisms, so that the energy demand for operation is now even lower for certain SF_6 circuit breakers than for the corresponding minimum oil circuit breaker.

The operating mechanisms have developed correspondingly. Earlier pneumatic- and hydraulic- operated mechanisms were typical, but there is a general trend towards spring-operated mechanisms.

2.2 Main components

Live tank circuit breakers consist of four main components:
- One or more breaking units (interrupters)
- Support insulator
- One or more operating mechanisms
- Support structure (stand)

The figures below shows the different parts of SF_6 circuit breakers.

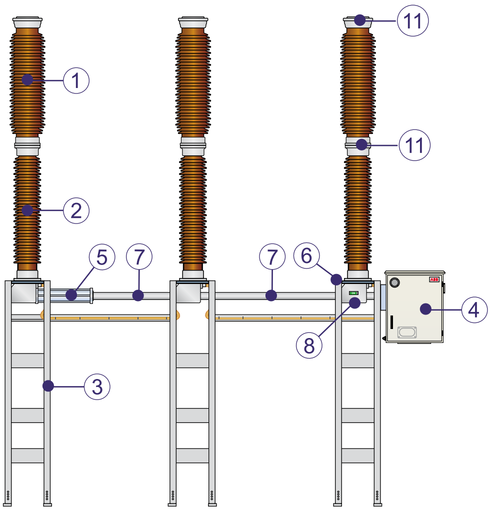


Figure 2.2. Three-pole operated circuit breaker with one interrupter per pole.

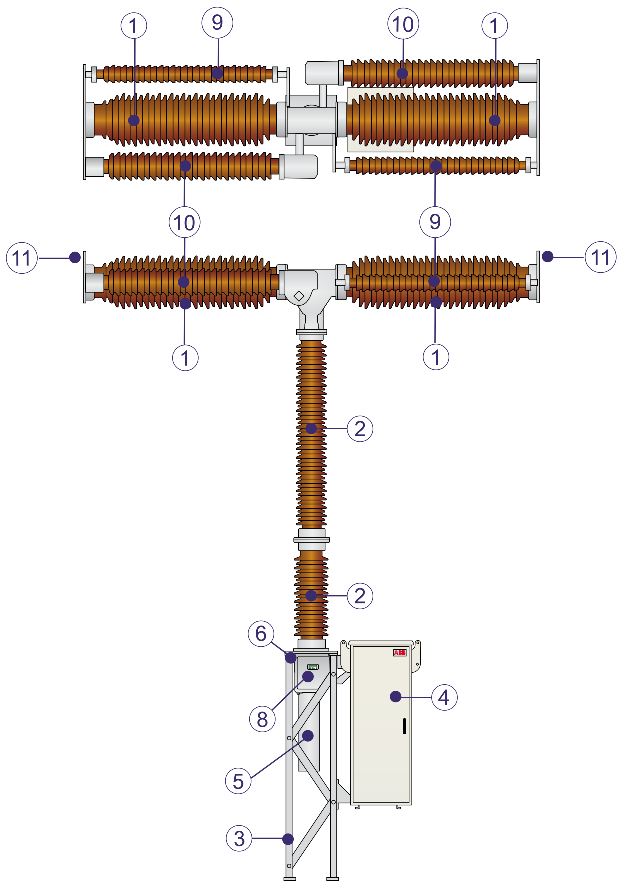


Figure 2.3. One pole of a single-pole operated circuit breaker with two interrupters per pole.

Circuit breaker components

1. Breaking unit	5. Trip mechanism	9. Grading capacitor (if required)
2. Support insulator	6. Gas supervision (on opposite side)	10. Preinsertion resistor (PIR) (if required)
3. Support structure	7. Pullrod with protective tube	11. Primary terminals
4. Operating mechanism	8. Position indicator	

2.2.1 Breaking unit

The insulating housing is made of porcelain or composite material and is filled with pressurized SF_6 gas. The breaking unit is subjected to potential, i.e. it is “live”, hence the term “live tank” circuit breaker.

One circuit breaker pole can even consist of two or more breaking units in series. The number of breaking units is dependent on the system voltage and the requirements on interrupting capability.

The function of the extinction chamber is described under 2.4.2 “Principles of arc extinction.”

2.2.2 Support insulator

The main function of the support insulator is to ensure sufficient insulation from the HV-terminals and the breaking unit(s) to ground. The support insulator is a hollow housing made of porcelain or composite material and contains SF_6 gas at the same pressure as the gas in the breaking units; the support insulator and the breaking unit(s) have a common gas atmosphere.

The insulated pull rod, (also called operating insulator) which is part of the linkage system between the operating mechanism and the main contacts, is mounted inside the support insulator.

2.2.3 Operating mechanism

The operating mechanism, together with the trip spring, stores the necessary energy for the closing and opening operation of the circuit breaker. Located at ground potential, the operating mechanism also includes secondary wiring, which acts as an interface to a network’s control and protection system.

2.2.4 Support structure

There are two versions of support structures (or support stand) for live tank circuit breakers:
- Three-column supports, i.e. each circuit breaker pole is mounted on its individual support.
- Pole-beam support, i.e. the three poles mounted on one common beam with two support legs.

The supports are usually made of hot-dip galvanized steel.

2.3 Additional components

2.3.1 Grading capacitors

For circuit breakers with two or more breaking units in series, the voltage (rated voltage as well as transient switching and lightning overvoltages) will usually not be evenly distributed across the interrupters. In order to avoid high voltage stresses across one of the breaking units, capacitors are often mounted in parallel with the interrupters. The capacitance is usually on the order of 900 – 1,600 pF per breaking unit.

The performance of circuit breakers is gradually improving, and nowadays grading capacitors are generally not needed at rated voltages up to 420 kV. The ABB circuit breaker of the HPL type has recently been verified by type tests to handle 550 kV without grading capacitors. This offers several advantages: easier transport and installation; lower mass, which improves the seismic withstand capability; decreases in leakage currents; and a reduced risk of ferroresonance in nearby inductive voltage transformers.

2.3.2 Preinsertion resistors

Preinsertion resistors on line circuit breakers are used occasionally at rated voltages 362 – 420 kV and more often at 550 – 800 kV. Their purpose is to reduce the voltage transients generated when a no-load transmission line is energized, or re-energized after a line fault.

The resistors are operated by the same operating mechanism as the main contacts.

Preinsertion resistors were previously sometimes used on circuit breakers for capacitor banks, reactor banks and transformers. For these applications, however, controlled switching is now widely used as a powerful means to reduce the switching transients. Modern SF_6 circuit breakers also have better switching properties than old circuit breaker types. This has generally made preinsertion resistors superfluous for these applications.

New technologies may also eliminate the need for preinsertion resistors for line circuit breakers. In many cases controlled switching can replace the resistors and reduce the voltage transients to the same extent as, or even better than, resistors. See ABB Controlled Switching, Buyer's and Application Guide.

2.3.3 Cabinets for central control

Circuit breakers for single-pole operation can be provided with cabinets for central control. These are convenient for local three-pole operation.

In some cases one of the operating mechanism cabinets is expanded to handle integration of the functions of the central control cabinet. This solution is sometimes referred to as "Master-slave" or ICC, Integrated Control Cubicle.

2.4 SF_6 Interrupters

2.4.1 SF_6 gas

High-voltage circuit breakers with SF_6 gas as the insulation and quenching medium have been in use throughout the world for more than 30 years. This gas is particularly suitable because of its high dielectric strength and thermal conductivity.

2.4.2 Principles of arc extinction

The current interruption process in a high-voltage circuit breaker is a complex matter due to simultaneous interaction of several phenomena. When the circuit breaker contacts separate, an electric arc will be established, and current will continue to flow through the arc. Interruption will take place at an instant when the alternating current reaches zero.

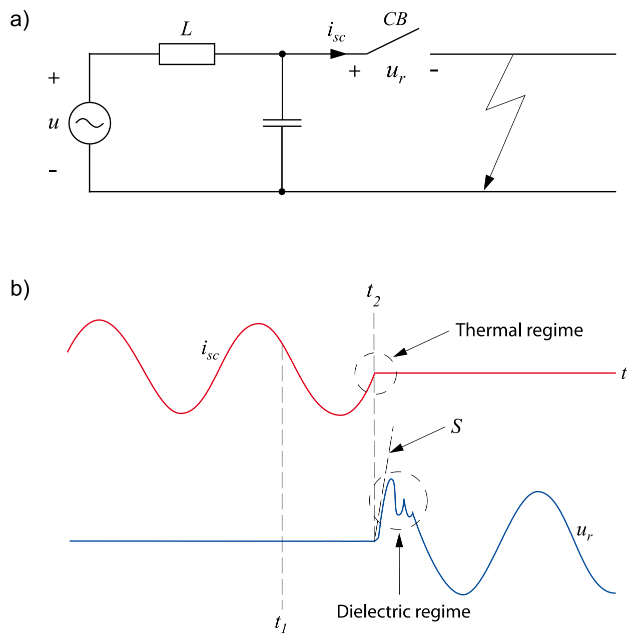
When a circuit breaker is tripped in order to interrupt a short-circuit current, the contact parting can start anywhere in the current loop. After the contacts have parted mechanically, the current will flow between the contacts through an electric arc, which consists of a core of extremely hot gas with a temperature of 5,000 to 20,000 K. This column of gas is fully ionized (plasma) and has an electrical conductivity comparable to that of carbon.

When the current approaches zero, the arc diameter will decrease, with the cross-section approximately proportional to the current. In the vicinity of zero passage of current, the gas has been cooled down to around 2,000 K and will no longer be ionized plasma, nor will it be electrically conducting.

Two physical requirements (regimes) are involved:

- Thermal regime: The hot arc channel has to be cooled down to a temperature low enough that it ceases to be electrically conducting.
- Dielectric regime: After the arc extinction, the insulating medium between the contacts must withstand the rapidly-increasing recovery voltage. This recovery voltage has a transient component (transient recovery voltage, TRV) caused by the system when current is interrupted.

If either of these two requirements is not met, the current will continue to flow for another half cycle, until the next current zero is reached. It is quite normal for a circuit breaker to interrupt the short-circuit current at the second or even third current zero after contact separation.



a) Simplified equivalent circuit.

b) Curves of short-circuit current i_{sc} and recovery voltage u_r

t_1 = contact separation

t_2 = arc extinction

S = rate of rise of recovery voltage

(The arc voltage from contact separation to arc extinction is low and has been disregarded)

Figure 2.4 Stresses on the extinction chamber at interruption.

2.4.2.1 Thermal regime

The thermal regime is especially critical at short-line fault interruption (see Section 3). The circuit parameters directly affecting this regime are the rate of decrease of the current to be interrupted (di/dt) and the initial rate of rise of the transient recovery voltage (du/dt) immediately after current zero. The higher the values of either of these two parameters, the more severe the interruption. A high value of di/dt results in a hot arc with a large amount of stored energy at current zero, which makes interruption more difficult. High values of du/dt will result in an increase of the energy to the post-arc current.

There exists a certain inertia in the electrical conductivity of the arc (see Figure 2.5). When the current approaches zero, there is still a certain amount of electrical conductivity left in the arc path. This gives rise to what is called a “post-arc current” with amplitude up to a few A. Whether or not the interruption is going to be successful is determined by a race between the cooling effect and the energy input in the arc path by the transient recovery voltage. When the scales of the energy balance tip in favor of the energy input, the circuit breaker will fail thermally. The thermal interruption regime for SF_6 circuit breakers corresponds to the period of time starting some μs before current zero, until extinguishing of the post arc current, a few μs after current zero.

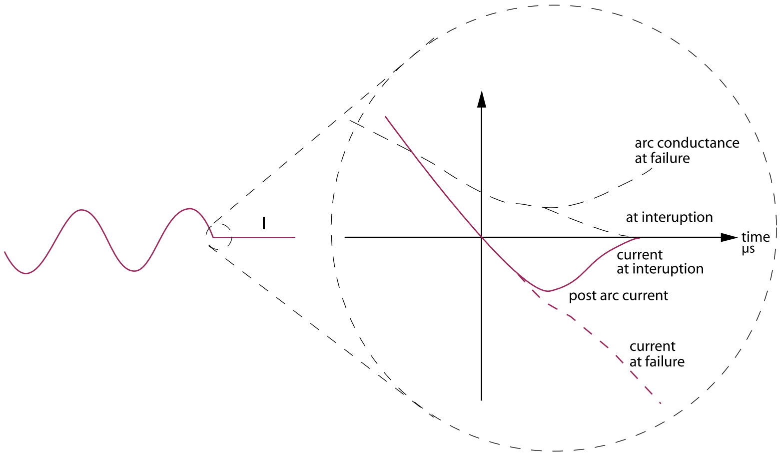


Figure 2.5 Current shape at interruption (the time scale is in the microsecond range).

2.4.2.2 Dielectric regime

When the circuit breaker has successfully passed the thermal regime, the transient recovery voltage (TRV) between the contacts rises rapidly and will reach a high value. For example, in a single-unit 245 kV circuit breaker the contact gap may be stressed by 400 kV or more 70 to 200 µs after the current zero.

In the dielectric regime the extinguishing/isolating medium is longer electrically conducting, but it still has a much higher temperature than the ambient. This reduces the voltage withstand capacity of the contact gap.

The stress on the circuit breaker depends on the rate-of-rise and the amplitude of the TRV.

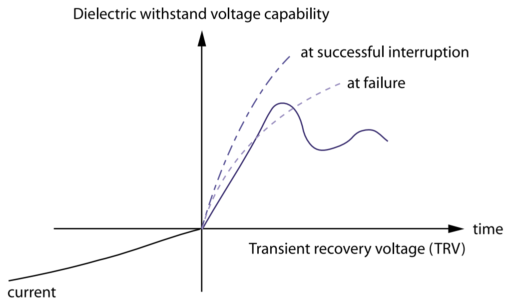


Figure 2.6 Dielectric interruption regime

The withstand capability of the contact gap must always be higher than the transient recovery voltage, see Figure 2.6, otherwise a dielectric reignition will occur (dielectric failure). This requires an extremely high dielectric withstand capability of the gas, which is still rather hot and therefore has low density.

2.4.3 Earlier interrupter designs

The first circuit breakers applying SF_6 gas had the extinguishing chamber divided into two separate parts with different pressures (double-pressure circuit breaker), operating on the same principle as air-blast circuit breakers. Nowadays all high-voltage SF_6 circuit breakers have extinguishing chambers which apply puffer or self-blast principles.

2.4.4 SF_6 puffer circuit breakers

In the SF_6 puffer, the gas pressure for the cooling blast is created during the opening stroke in a compression cylinder. In the opening operation, the compression of the gas will start at the same time as the contacts start their motion. The compressed gas is blown out through an insulating nozzle in which the arc is burning. Figure 2.7.2 shows the function of a puffer interrupter. The insulating nozzle is normally made of PTFE (Teflon).

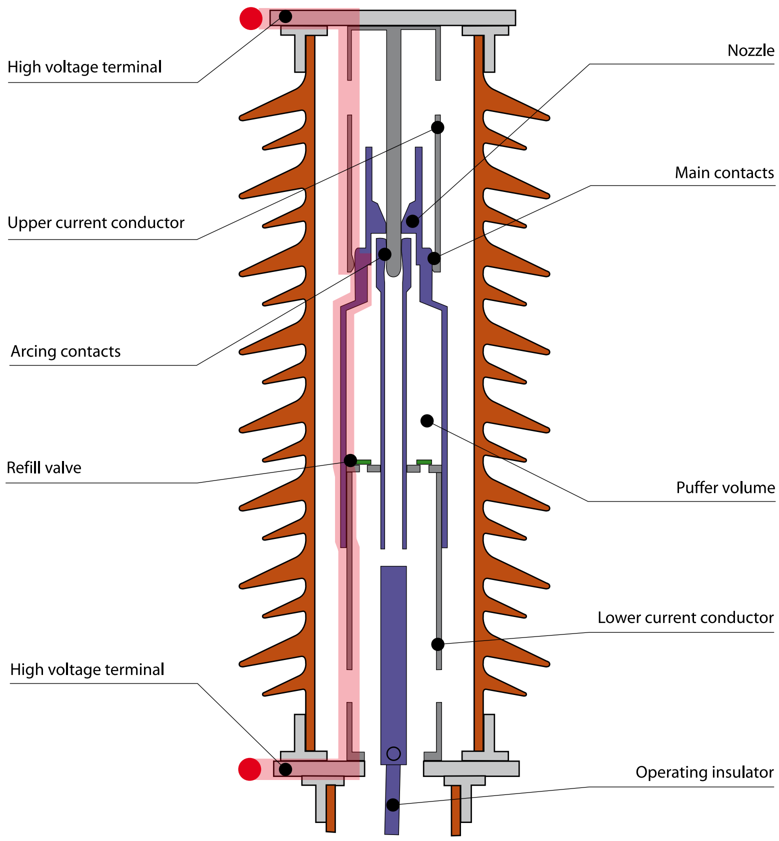


Figure 2.7.1 Main components of the puffer interrupter. Red color indicates the current path through the closed interrupter.

2. Live tank circuit breaker designs and operating principles

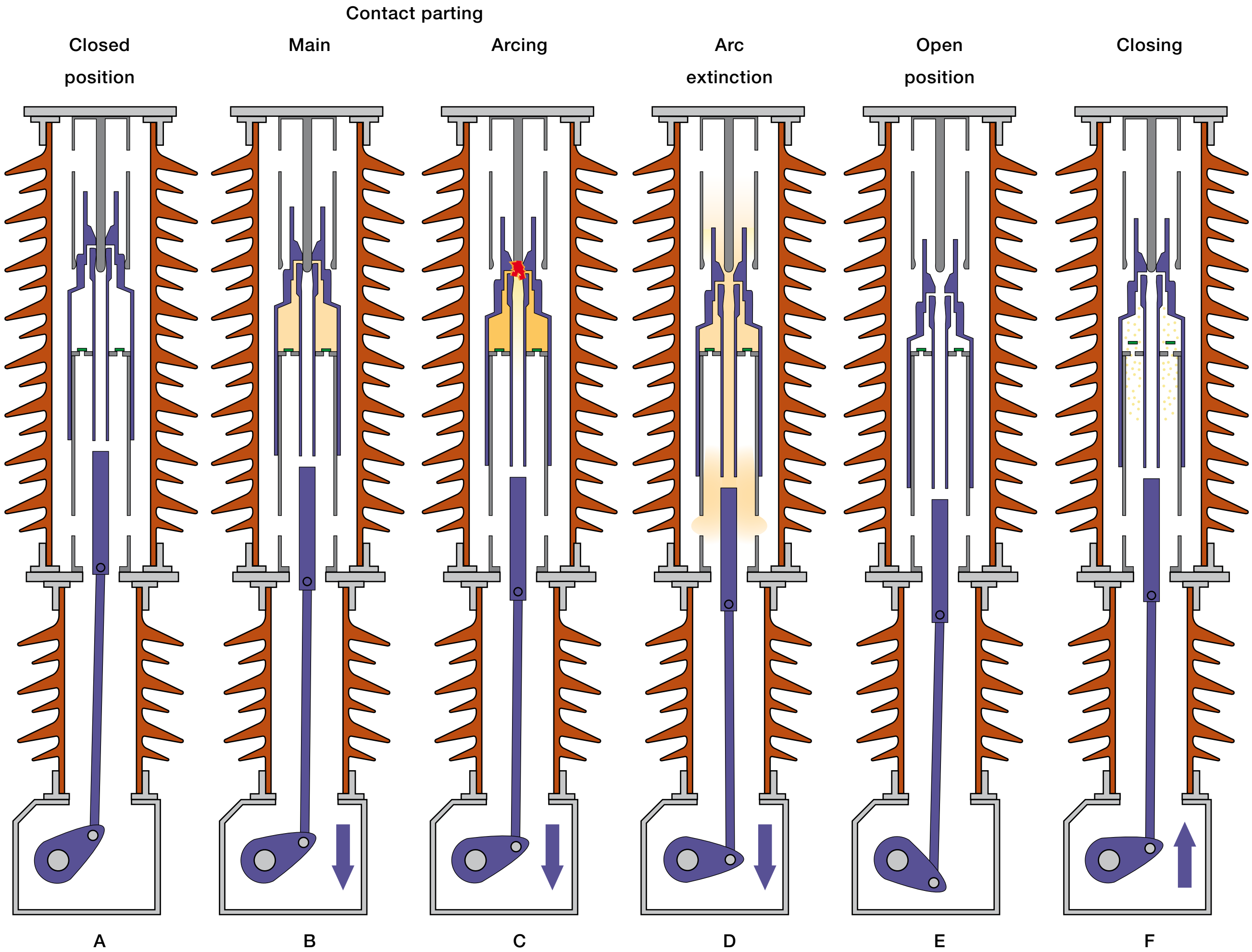


Figure 2.7.2 Function of a puffer interrupter:

A. Closed position. The current is conducted through the main contacts.

B. Separation of main contacts. The moving contacts have started to change position, the main contacts have parted. The current is commutated to the arcing contacts. Pressure is starting to build up in the puffer volume.

C. After separation of the arcing contacts an arc is established between them. Pressure in the puffer volume continues to increase.

D. Arc extinction. The current approaches zero and the cold gas from the puffer volume blasts up through the nozzle, cooling the arc and extinguishing it.

E. The contacts are now fully open; the motion has been damped and stopped by the operating mechanism.

F. During closing the contacts close and the puffer volume is refilled with cold gas, making it ready for the next opening operation.

One important feature of the puffer design is the current-dependent build-up of extinguishing pressure. At a no-load operation (without arc) the maximum pressure in the puffer cylinder is typically twice the filling pressure. See the no-load curve in Figure 2.8.

A heavy arc burning between the contacts blocks the gas flow through the nozzle. When the current decreases towards zero, the arc diameter also decreases, leaving more and more outlet area free for the flow of gas. A full gas flow is thus established at the current zero, resulting in maximum cooling when needed. The blocking of the nozzle (nozzle clogging) during the high current interval gives a further pressure build-up in the puffer cylinder that may be several times the maximum no-load pressure (see Figure 2.8).

In other words: the decreasing puffer volume, nozzle clogging and heating of the gas by the arc interact to create a high pressure.

The high pressure in the puffer requires a high operating force. The blast energy is therefore almost entirely supplied by the operating mechanism.

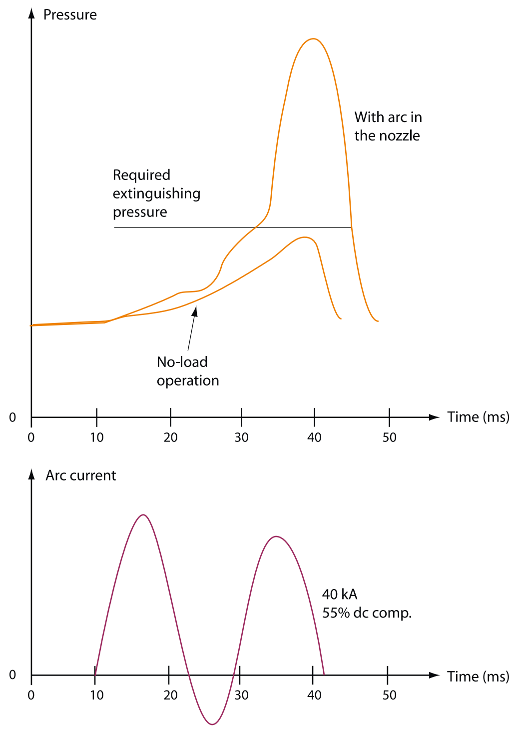


Figure 2.8. Pressure in the puffer volume at no-load operation and during interruption of an asymmetrical short-circuit current of 40 kA

In order to extinguish the arc, a certain blast pressure is required and is determined by the rate-of-change of current at current zero (di/dt) and the rate of rise of the recovery voltage immediately after current zero (du/dt) as described under 2.4.2.1.

2.4.5 SF_6 self-blast circuit breakers

Service experience has shown that circuit breaker failures due to insufficient interrupting capacity are rare. The majority of the failures reported are of a mechanical nature, which is why efforts are made to improve the overall reliability of the operating mechanisms. Because of the fact that puffer circuit breakers require high operating energy, the manufacturers were forced to use pneumatic mechanisms, hydraulic mechanisms or high-energy spring mechanisms.

In a normal puffer circuit breaker, the major part of the blast pressure is created with energy from the operating mechanism. The ideal situation would be to let the arc produce the blast pressure. In this way, the operating mechanism only needs to deliver energy necessary for the movement of the contact. However, this ideal situation cannot currently not be reached at higher voltages. Problems will arise when interrupting small currents, since there is only a limited amount of energy available for the pressure rise. For this reason a compromise has been reached: a self-blast circuit breaker with pre-compression.

The self-blast principles represented a large step forward on the way to reducing the operating energy.

The self-blast technology has several designations: auto-puffer, arc-assisted circuit breaker, thermal-assisted circuit breaker or simply self-blast circuit breaker.

Because the blast pressure required for interruption of low currents and low current derivatives (see 2.4.2.1) is moderate, a small pressure rise independent of the current is sufficient. For higher currents, the energy producing the blast pressure is taken from the arc through heating of the gas.

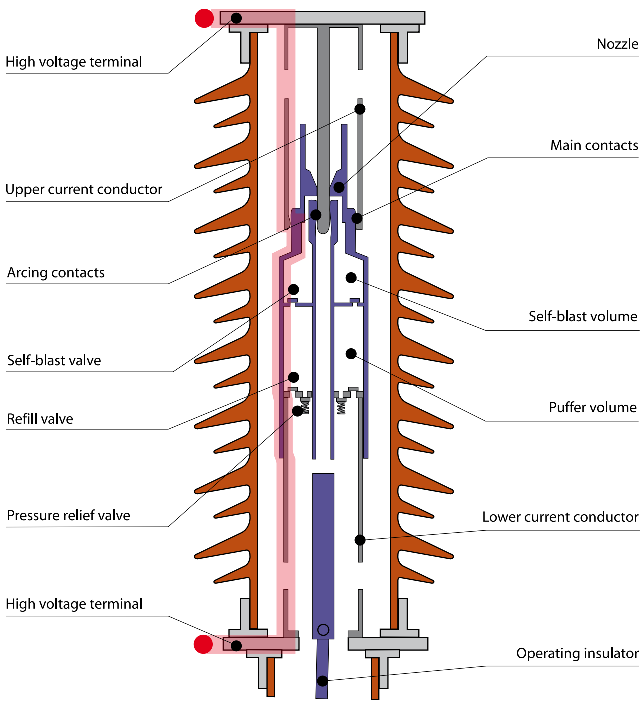


Figure 2.9.1 Main components of the self-blast interrupter. Red color indicates the current path through the closed interrupter.

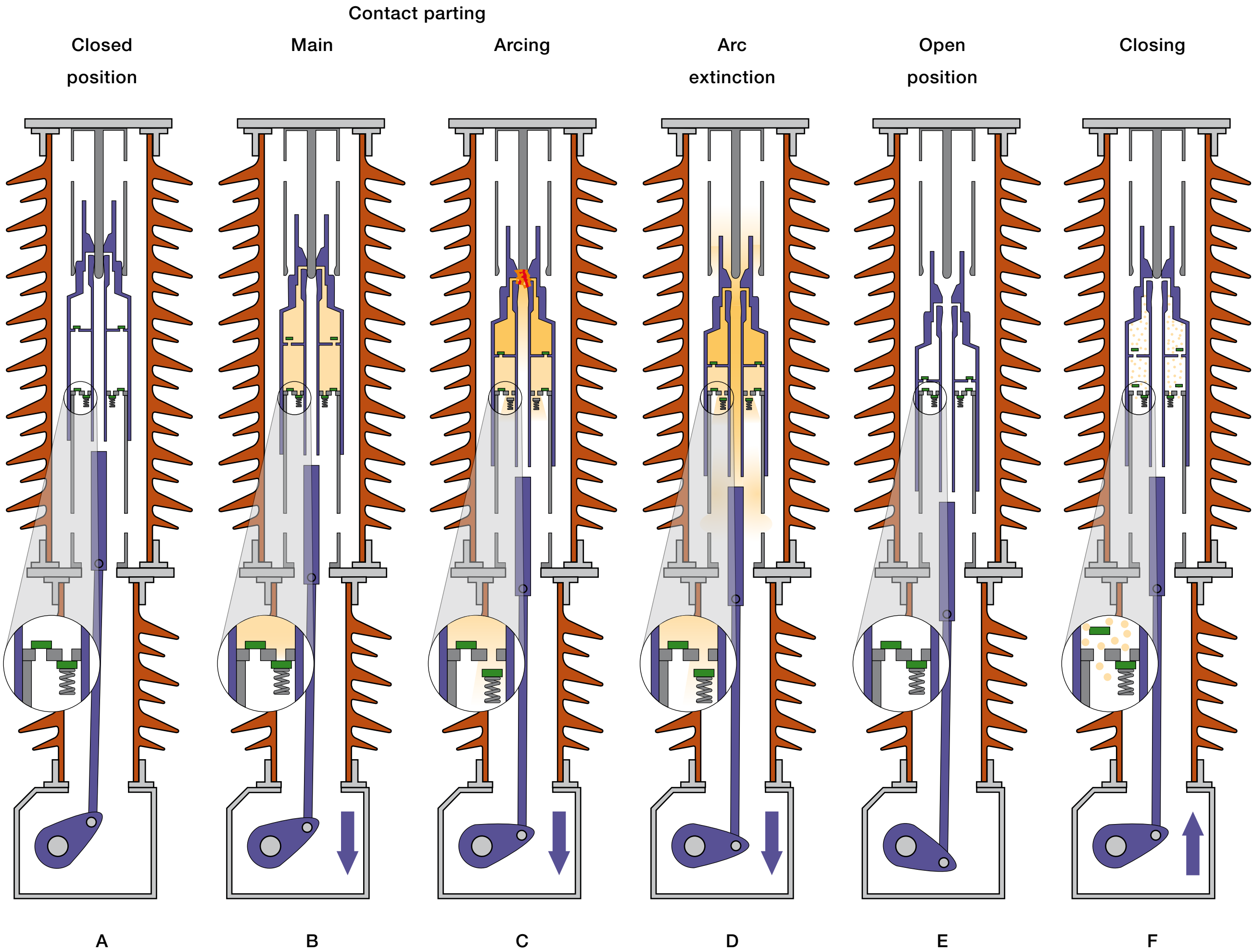


Figure 2.9.2 Self-blast SF_6 interrupter with pre-compression. The figure shows high current interruption.

A. Closed position. The current is conducted through the main contacts.

B. Separation of main contacts. The moving contact has started to change position, the main contacts have parted. Pressure is starting to build up in the puffer and self-blast volumes. The current is commutated to the arcing contacts.

C. After separation of the arcing contacts an arc is established between them. Heat from the arc generates pressure in the self-blast volume, the valve closes when the pressure is higher than in the puffer volume.*

D. Arc extinction. The current approaches zero and the gas from the self-blast volume blasts up through the nozzle, cooling the arc and extinguishing it. Excessive pressure in the puffer volume is released through the pressure relief valve.

E. The contacts are now fully open; the motion has been damped and stopped by the operating mechanism.

F. During closing the contacts close and the puffer volume is refilled with cold gas, making it ready for the next opening operation.

* At low breaking current the pressure generated by the arc will not be sufficient to close the valve. The self-blast interrupter will then operate as a puffer interrupter.

As can be seen in Figure 2.9.1, the extinction chamber is divided into two sections: the self-blast volume and the puffer volume. The two sections are separated by the self-blast valve.

When high-fault currents are interrupted, the pressure in the self-blast volume generated by the arc will be so high that the valve will close, preventing the gas from escaping into the puffer volume. Instead, the pressurized gas will flow through the nozzle and extinguish the arc.

At lower currents, typically a few kA, the arc will not have sufficient energy to generate a pressure high enough to close the valve and the interrupter will function as a puffer interrupter.

The pressure in the puffer volume is relatively independent of the current whether the circuit breaker operates as a self-blast interrupter or as a puffer interrupter. It is limited to a moderate level by means of a spring-loaded valve (overpressure valve), which means that the compression energy required from the operating mechanism is limited. Figure 2.10 shows how the energy from the operating mechanism is used.

Compared with a conventional puffer circuit breaker of the same rating, the energy requirements of the operating mechanism can be reduced to 50% or less.

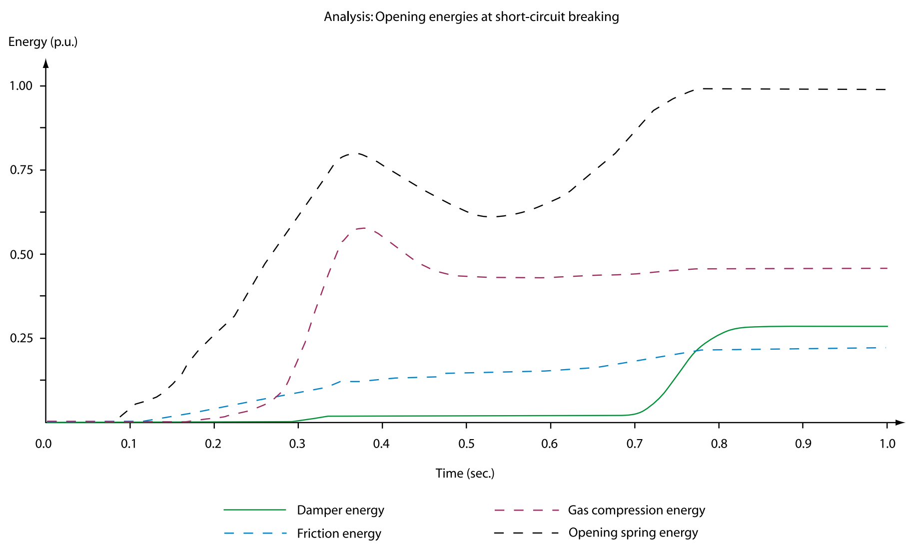


Figure 2.10 Utilization of operating energy at a breaking operation

2.4.6 Configuration of the moving contacts

For the self-blast circuit breakers, several different principles of moving contact configurations exist. Their purpose is to further decrease the amount of energy needed for the operation of the circuit breaker.

The single-motion design dominates the market today. This is the simplest type of design, utilizing one moving set of arcing and main contacts.

The double-motion design uses a linkage system to move both the puffer with the lower contact system, and the upper arcing contact, in different directions. This means that the speed requirement from the operating mechanism is drastically reduced, since the contact speed will be the relative speed between the upper and lower contacts. The main benefit of the double-motion arrangement is the minimized energy need for the contact movement due to lower speed demands. This is visualized by the equation for kinetic energy:

$$W = \frac{mv^2}{2}$$

The triple-motion design is based on the double-motion design, but moves the upper shield at a different speed than that of the upper arcing contact to optimize the distribution of the electrical fields and get a better dielectrical performance.

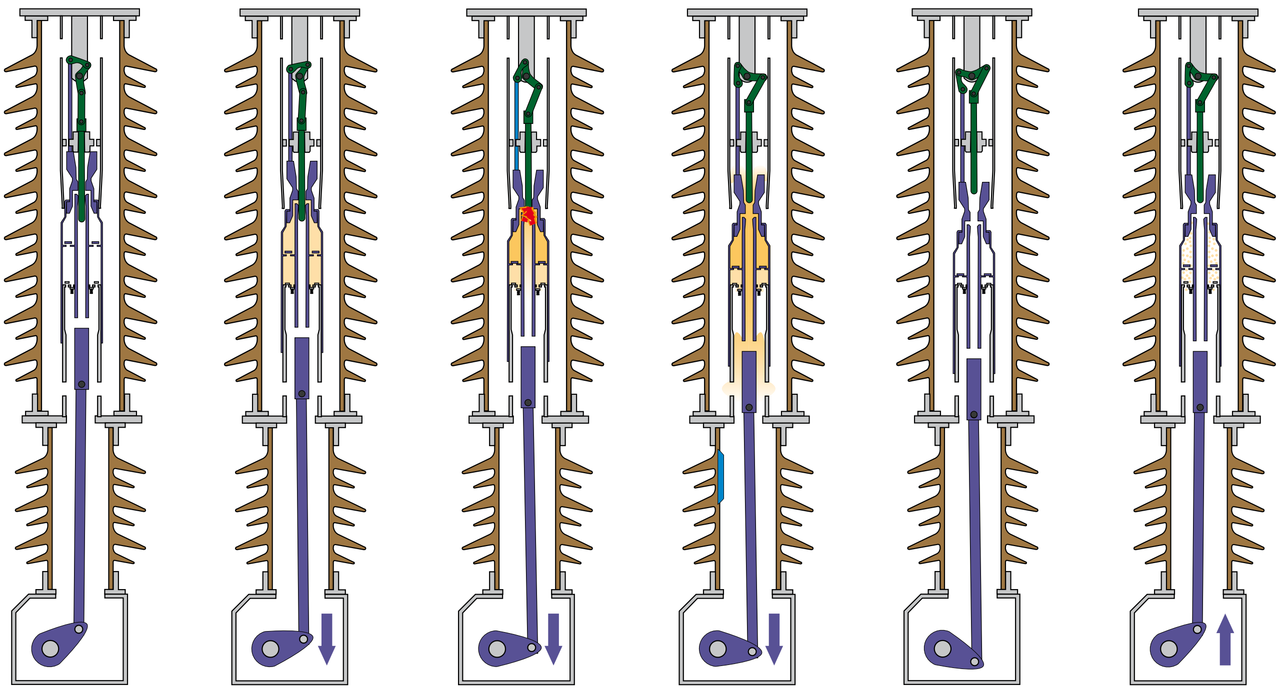


Figure 2.11 Double motion design

2.5 Operating mechanisms

2.5.1 General

The main requirement of the operating mechanism is to open and close the contacts of the circuit breaker within a specified time. The operating mechanism shall provide the following consecutive functions:

– Charging and storing of energy
– Release of energy
– Transmission of energy
– Operation of the contacts

In addition, an operating mechanism shall provide control and signaling interface to a network's control and protection system.

Figures 2.2 and 2.3 show the location of the operating mechanism.

A requirement common to most circuit breakers, regardless of the type of operating mechanisms, is to carry out an open-close-open (O - 0.3 s - CO) sequence with no external power supply to the operating mechanism. The circuit breaker shall, after a closing operation, always be able to trip immediately without intentional time delay.

For circuit breakers intended for rapid auto-reclosing, the operating duty cycle in accordance with IEC 62271-100 is:

O - 0.3 s - CO - 3 min - CO

The time of 3 min is the time needed for the operating mechanism to restore its power after a O - 0.3 s - CO. Modern spring and hydraulic operating mechanisms do not need 3 min to restore their power, as an alternative IEC specifies that the time values 15 s. or 1 min. can also be used. The dead time of 0.3 s is based on the recovery time of the air surrounding an external arc in the system (i.e. a short-circuit).

Sometimes the operating sequence CO - 15 s - CO is specified.

2.5.2 Spring-operated mechanism

In the spring mechanism, the energy for open and close operation is stored in springs. When the mechanism's control system receives an open or close command, the energy stored in the spring will be released and transmitted through a system of levers and links and the contacts will move to the open or closed position.

In most designs the closing spring has two tasks: to close the contacts, and at the same time to charge the opening spring (or springs). Thus the criteria stated above are fulfilled; the circuit breaker in closed position is always ready to trip.

After the O - 0.3 s - CO operation, the closing spring will be recharged by an electric motor, a procedure that lasts 10-20 seconds. The circuit breaker will then be ready for another CO operation.

One example of a spring mechanism is shown in Figure 2.12. This type of mechanism has a set of parallel helical wound springs with linear motion. The electric motor charges the springs via an endless chain. When the closing latch is released, the energy stored in the springs is transmitted via a rotating cam disc and a system of levers and links to the circuit breaker pole or poles. The trip spring is in this case located outside the operating mechanism.

Instead of helical springs, clock springs may be applied. The function is the same as for the helical springs described above. Figure 2.13 shows a system with clock spring for closing operation.

The advantage of the spring-operated mechanism is that the system is purely mechanical; there is no risk of leakage of oil or gas, which could jeopardize the reliability. A well-balanced latching system provides stable operating times.

Furthermore, the spring system is less sensitive to variations in temperature than pneumatic or hydraulic mechanisms are. This ensures stability even at extreme temperatures.

The spring mechanism has fewer components than hydraulic and pneumatic mechanisms, which improves its reliability.

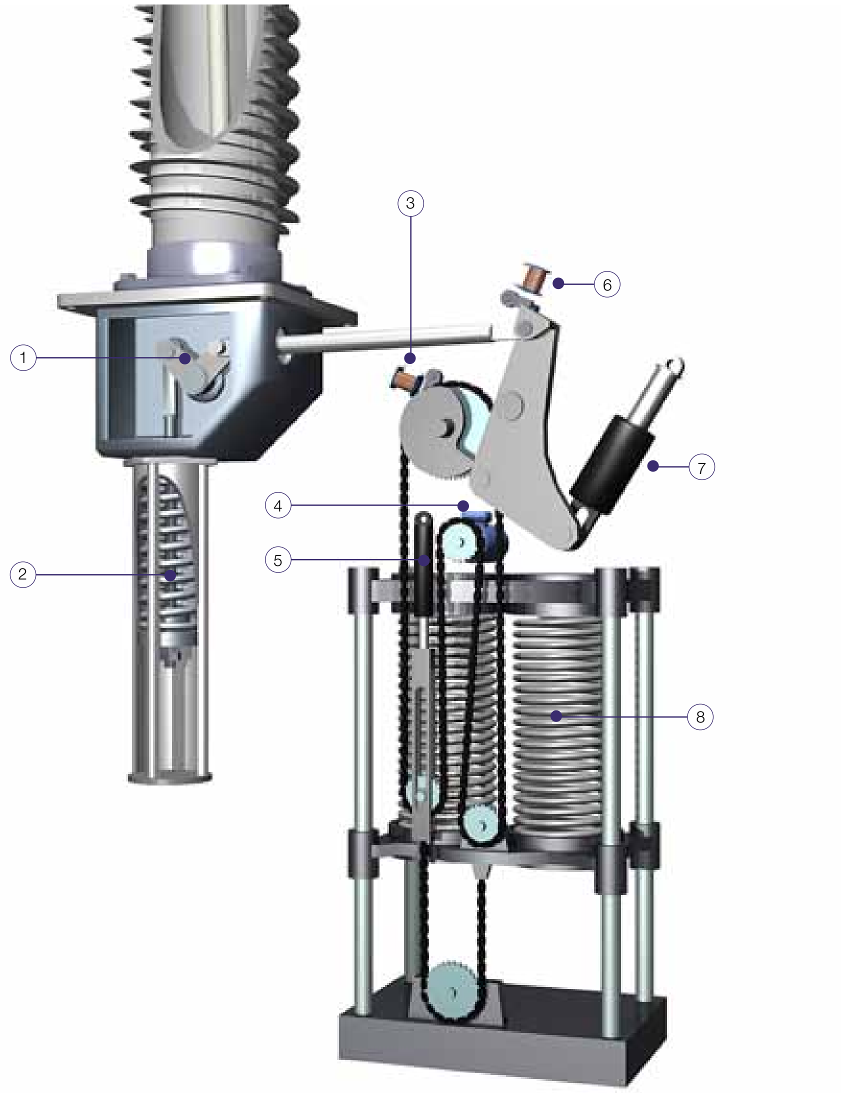


Figure 2.12 Spring operating mechanism with helical wound springs.
Trip and close springs in charged position. ABB type BLG.

1.	Link gear	5.	Closing damper
2.	Trip spring	6.	Tripping latch with coil
3.	Closing latch with coil	7.	Opening damper
4.	Motor	8.	Close springs

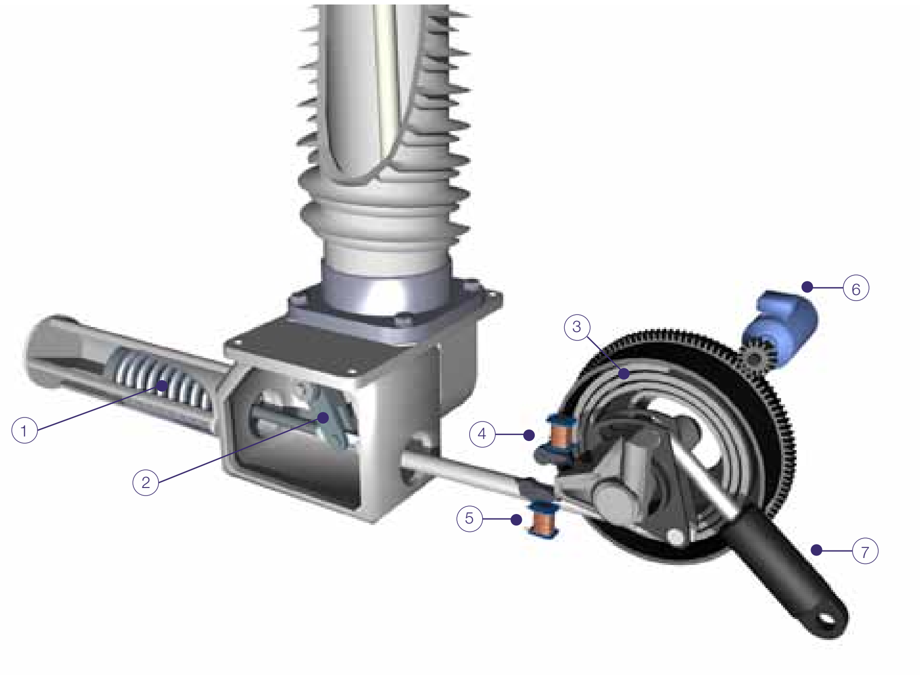


Figure 2.13 Spring operating mechanism with clock spring. ABB type BLK.

1. Trip spring	5. Closing latch with coil
2. Link gear	6. Motor
3. Close spring	7. Opening damper
4. Tripping latch with coil	

2.5.3 Motor Drive

One of the most recently-developed operating mechanisms is the electrical motor drive. The motor drive uses a servomotor to perform a smooth and silent operation of the circuit breaker. The operation is actively controlled by a sensor which continuously reads the position of the motor and adjusts the motor current to obtain an optimal travel curve. The energy is stored in a capacitor bank and can be delivered instantaneously to the converter, which transforms dc from the capacitors and feeds the motor with regulated ac.

The major advantage of the motor drive is the minimized mechanical system, which reduces the service need to a minimum and makes the technology ideal for applications with frequent operation.

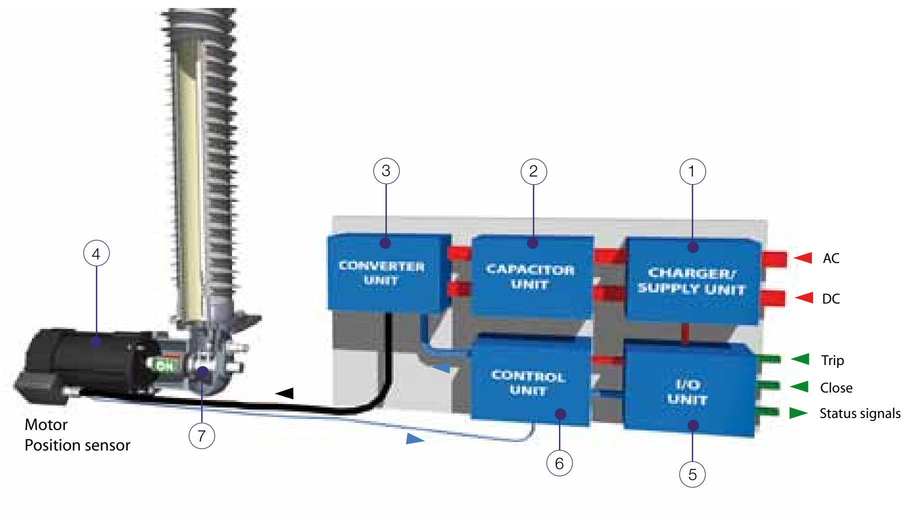


Figure 2.14 Block diagram showing function of the Motor Drive

1. Charger unit that converts supply voltage and feeds the capacitors and internal electronics.
2. Capacitor unit stores the energy for operation.
3. The converter unit transforms dc from the capacitors to ac for the motor.
4. Servomotor that delivers the force to move the contacts, integrated position sensor gives information to the control unit.
5. The I/O unit takes care of signaling between the station control system and the operating mechanism.
6. Control unit that controls and regulates the motion of the contacts. The interlock functions are also handled by this module.
7. Link gear that transforms rotary movement to linear movement.

2.5.4 Pneumatic-operated mechanism

The pneumatic-operated mechanism uses compressed air as energy storage, and pneumatic cylinders for operation. Solenoid valves allow the compressed air into the actuating cylinder for closing or for opening. The compressed-air tank is replenished by a compressor unit. The use of pneumatic operating mechanisms is decreasing. Due to the high operating pressure, there is always a risk of leakage of air, particularly at low temperatures. There is also a risk of corrosion due to humidity in the compressed air.

2.5.5 Hydraulic-operated mechanism

The hydraulic mechanism usually has one operating cylinder with a differential piston. The oil is pressurized by a gas cushion in an accumulator, and the operating cylinder is controlled by a main valve.

The hydraulic mechanism has the advantages of high energy and silent operation. However, there are also some disadvantages. There are several critical components which require specialized production facilities. The risk of leakage cannot be neglected as the operating pressure is in the range of 30-40 MPa (300-400 bar). It is necessary not only to check the pressure as such but also to supervise the oil level in the accumulator or, in other words, the volume of the gas cushion. Large variations in temperature lead to variations in operating time.

Until recently several manufacturers used hydraulic mechanisms for their SF_6 circuit breakers. However, with the introduction of self-blast circuit breakers, the requirement of high energy for operation is decreasing and the hydraulic mechanisms are losing ground to spring-operated mechanisms.

2.5.6 Hydraulic spring-operated mechanism

The hydraulic spring-operated mechanism is an operating mechanism combining hydraulics and springs. Energy is stored in a spring set, that is tensioned hydraulically. A differential piston, powered by oil that is pressurized by the spring package, is used to operate the circuit breaker during opening and closing.

Figure 2.15 Hydraulic spring-operated mechanism. ABB type HMB

2.5.7 Other types of operating mechanisms

In addition to the types of operating mechanisms mentioned above, there are other variants, e.g. a design which basically applies the same technology as the pneumatic mechanisms but with SF_6 gas instead of air.

Another design is the magnetic actuator mechanism, which is applied only for certain medium-voltage circuit breakers.

3. Current switching and network stresses

3.1 Short-circuit currents

A circuit breaker should be able to interrupt both symmetrical and asymmetrical short-circuit currents. Asymmetrical short-circuit currents consist of a symmetrical component superimposed on a dc component. The dc component will decrease with time.

Consider a part of a typical network as shown in Figure 3.1. At normal operation, load currents of the magnitude of approximately 100 amperes will flow in the different branches. If a short-circuit occurs somewhere in the system, the currents will change dramatically into short-circuit currents that are two or three orders of magnitude higher than the load currents.

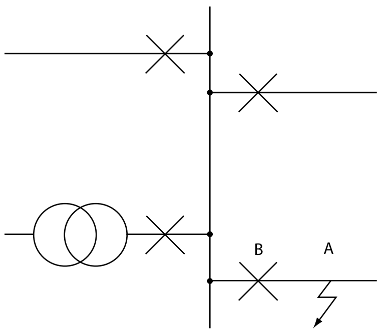


Figure 3.1 Network with short-circuit

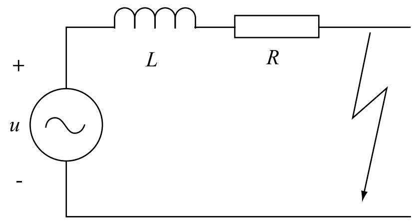


Figure 3.2 Single-phase equivalent network

With a short-circuit in point A, the system may, in a simple approximation, be represented by a single-phase equivalent network as shown in Figure 3.2. The inductance L may be obtained from the short-circuit power (fault level) S_k of the network as:

$$L = \frac{1}{\omega} \cdot \frac{U^2}{S_k}$$

In this equation ω is the angular frequency ($2\pi f$) and U is the system voltage (phase-to-phase).

The resistance R represents the losses in the network. It is normally low compared to the inductive reactance $X = \omega L$, perhaps 5 to 10%. The voltage source u in Figure 3.2 is the phase-to-neutral voltage.

Figure 3.3 shows the voltages and currents associated with a short-circuit at point A. Up to the short-circuit instant - which has been chosen arbitrarily - the current is low and has been shown as a zero line in the figure. After the short-circuit has occurred, the current will approach a steady state symmetrical value i_{sym}. The phase angle will be almost 90° lagging, since the circuit is more or less purely inductive.

Since the current in an inductive circuit can not be discontinuous at the short-circuit instant, the total short-circuit current (i_{total}) will consist of a symmetrical part i_{sym} and dc component i_{dc}:

$$i_{total} = i_{sym} + i_{dc}$$

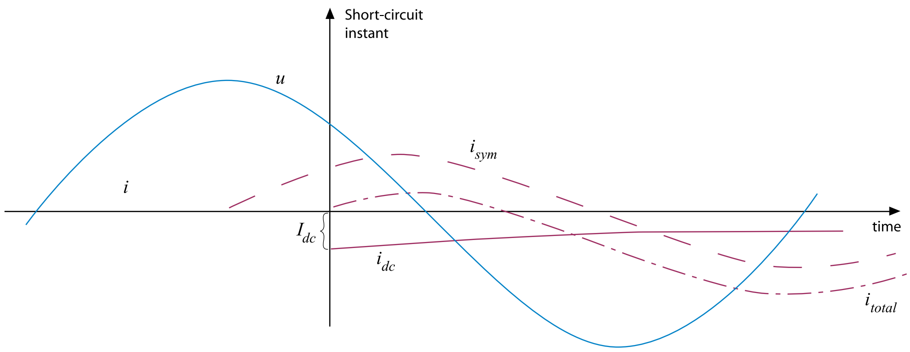


Figure 3.3 Current and voltage at short-circuit

The initial magnitude I_{dc} of the dc component will be equal to the instantaneous value of the symmetrical short-circuit current i_{sym} at the short-circuit instant and has the opposite polarity. In this way the transition from load to short-circuit current will be continuous.

The dc component will follow an exponentially damped curve and can be written as:

$$i_{dc} = I_{dc} \cdot e^{-\frac{t}{\tau}}$$

where:

t	time from initiation of the short-circuit
τ	the time constant of the network

τ is determined by the losses of the circuit, $\tau = L/R$ and is of the order of 20 - 60 ms in typical networks.

3.1.1 Standardized time constant and asymmetry

Both IEC and IEEE use a standard value of the time constant, τ = 45 ms. This value covers most cases.

Sometimes specification of the time constant is replaced by specification of the X/R (= $\omega L/R$) ratio of the network. This value depends on the network frequency. The standard time constant 45 ms corresponds to X/R = 14 at 50 Hz, and X/R = 17 at 60 Hz.

Normally the amount of asymmetry of the current at a certain instant of time is given by stating the dc component as a percentage of the (peak value of) symmetrical current.

The dc component used for type testing of a circuit breaker is determined as follows (refer to IEC 62271-100):

“For a circuit-breaker that is intended to be tripped solely by means of auxiliary power (e.g. by giving an impulse to a device that releases the circuit-breaker for operation), the percentage dc component shall correspond to a time interval equal to the minimum opening time T_{op} of the circuit-breaker plus one half-cycle of rated frequency T_r.” (See also Figure 3.4).

Example:
What is the dc component required for a circuit breaker having a minimum opening time of 18 ms, used on a 50 Hz system with a time constant of 45 ms?

Answer:
Minimum opening time: T_{op} = 18 ms
Rated frequency 50 Hz gives T_r = 10 ms
T_{op} + T_r = 18 + 10 = 28 ms leads to a dc component of 54% (see Figure 3.4)
For rated frequency 60 Hz (T_r = 8.3 ms) the dc component is 56%.

The r.m.s. value of the asymmetrical current (also known as the total current) can be determined using the following formula:

$$I_{asym} = I_{sym} \cdot \sqrt{1+2p^2}$$

where:

p	the dc component in p.u.
I_{sym}	the rms. value of the symmetrical part

Sometimes it is necessary to use larger values for the time constant than 45 ms. For example, this can be the case close to large generator units, where the network resistance is low. For such situations IEC specifies alternative, “special case time constants”:
- 120 ms for rated voltages up to and including 52 kV
- 60 ms for rated voltages from 72.5 kV up to and including 420 kV
- 75 ms for rated voltages 550 kV and above

In order to minimize special testing, etc. it is preferable that these values are applied when the standard value 45 ms cannot be used.

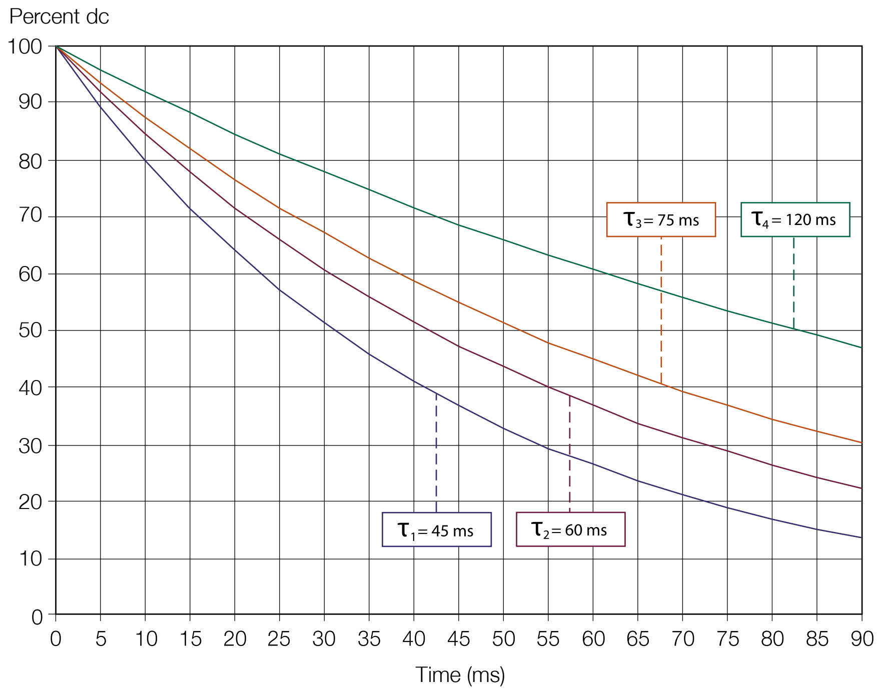


Figure 3.4 Percentage dc component in relation to time (from IEC 62271-100)

3.1.2 Peak withstand current

Due to the dc component, the short-circuit current will be asymmetrical for a certain time after the initiation of the short-circuit. On the one hand, this has to be considered when designing circuit breakers which will be called upon to interrupt such currents. On the other hand, this is important for all the components in the network, since the mechanical stresses due to the currents will be most severe at the maximum peak of the asymmetrical short-circuit current.

The highest possible current peak will occur if the short-circuit is initiated at the zero passage of the voltage. The probability of this happening in the network is low, but needs to be considered. Lightning strikes occur at random time instants, and can therefore in the worst case initiate short-circuits when the instantaneous voltage in the system is zero. In contrast, any short-circuits caused by the system voltage itself, e.g. in the case of damaged or polluted insulation systems, will mainly occur close to the peak value of the voltage in the system.

The initial value of the dc component in the worst case would be:

$$I_{dc} = \sqrt{2}\ I_{sym}$$

Half a period later (10 ms at 50 Hz) the peak value would occur. Assuming a rated frequency of 50 Hz and a time constant of 45 ms, the peak value would be:

$$I_{peak} = \sqrt{2}\ I_{sym}\ (1 + e^{-\frac{10}{45}}) = 2.5\ I_{sym}$$

At 60 Hz the peak value would be:

$$I_{peak} = \sqrt{2}\ I_{sym}\ (1 + e^{-\frac{8.3}{45}}) = 2.6\ I_{sym}$$

Based on this relation IEC specifies that, in cases with time constant 45 ms, the peak withstand current is 2.5 times the r.m.s. value of the symmetrical short-circuit current at 50 Hz. For 60 Hz, both IEEE and IEC specify a multiplying factor of 2.6. For the "special case time constants," larger than 45 ms, the multiplying factor is 2.7.

A circuit breaker must be able to cope with the maximum peak current in closed position (rated peak withstand current). In addition, it must be able to withstand the same peak current in the event that the short-circuit is initiated by a closing operation of the circuit breaker (rated short-circuit making current).

3.2 Terminal faults

Terminal faults are faults located directly at/or in the vicinity of the circuit breaker terminals. In this case, the total short-circuit impedance is equal to the source side impedance. Consequently, the terminal fault is the condition that gives the highest short-circuit current.

3.2.1 Transient Recovery Voltage (TRV) in single-phase networks

Consider again the network in Figure 3.1 with a short-circuit at point A and the equivalent network shown in Figure 3.2. In order to understand what happens when the short-circuit is interrupted by the circuit breaker in point B, the same network may be used, only with the addition of a capacitance C, representing the total stray capacitance in the source side network. See Figure 3.5.

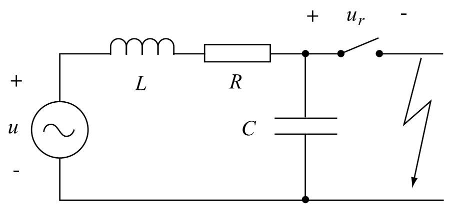


Figure 3.5 Single-phase equivalent network for determination of the TRV

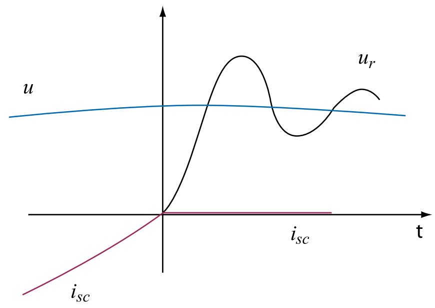


Figure 3.6 Current and voltage at interruption

Figure 3.6 shows the current and the voltage at interruption of the current. The circuit breaker will only interrupt the current at a current zero. At this instant the supply voltage u of the network is close to its peak value, since the circuit is almost purely inductive. The voltage across the circuit breaker is low (equal to the arc voltage) as long as the current has not been interrupted. After interruption, this voltage will approach the value of the supply voltage through a transient oscillation with a frequency determined by L and C of the network. The overshoot will typically be of the order of 40 - 60%. (Had the circuit been entirely without losses, R = 0, the overshoot would have been 100%).

The voltage across the circuit breaker after interruption is called the recovery voltage. The first oscillatory part of it is referred to as the Transient Recovery Voltage (TRV), while the later part is called power frequency recovery voltage. The power frequency recovery voltage is equal to the open-circuit voltage of the network at the location of the circuit breaker.

Both the Rate of Rise of Recovery Voltage (RRRV) and the peak value of the TRV are important parameters. Together with the magnitude of the current, these parameters determine the severity of the switching case. The ratio of the peak of the TRV and the peak of the source side voltage is called the amplitude factor.

The equivalent network in Figure 3.5 is applicable in situations with short lines. In systems with long lines, it is less reasonable to use an equivalent network with a only a lumped inductance and capacitance, and the recovery voltage will have a more complicated shape. Figure 3.7a, b and c shows three different simplified situations.

- In Figure 3.7a, the network consists of relatively short lines (typical for distribution networks), and the TRV is a damped, single-frequency oscillation. This is the same situation as in Figure 3.6.
- In Figure 3.7b, the network is dominated by an extremely long line. In this case the TRV will have approximately an exponential wave shape.
- Finally, in Figure 3.7c, the line is shorter, and reflected voltage waves from the remote end of the line will add to the TRV wave shape.

TRV shapes in different simplified networks

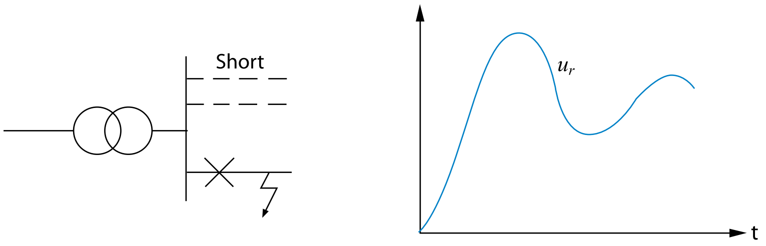


Figure 3.7a

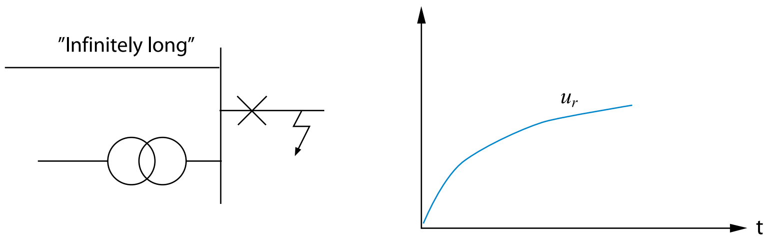


Figure 3.7b

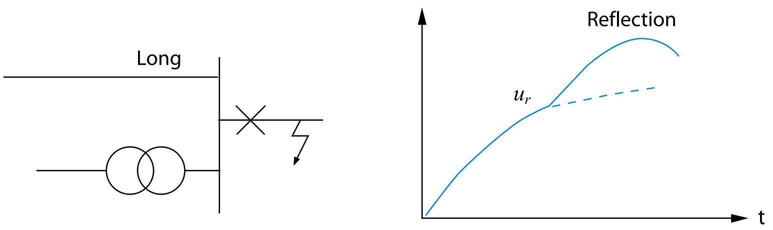


Figure 3.7c

Typical networks with relatively high rated voltage will have TRV wave shapes that are combinations of the single-frequency response of Figure 3.7a and the exponential (with reflection) of Figure 3.7c.

Both IEC and IEEE have the same approach for specification of the standard transient recovery voltages:

- For rated voltages below 100 kV, a TRV waveshape as illustrated in Figure 3.7a is assumed. It is described by means of two parameters, u_c and t_3, see Figure 3.8a.
- For rated voltages 100 kV and above, a TRV waveshape that is essentially a combination of Figure 3.7a and 3.7c is assumed. It is described by means of four parameters, u_1, u_c, t_1 and t_2, see Figure 3.8b. This four-parameter method is used for high breaking currents (terminal fault type tests at 100% and 60% of rated breaking current), while the two-parameter method is used for lower breaking currents.

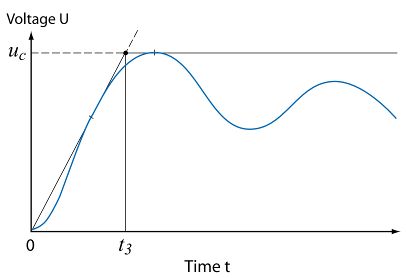


Figure 3.8a TRV with 2-parameter reference line

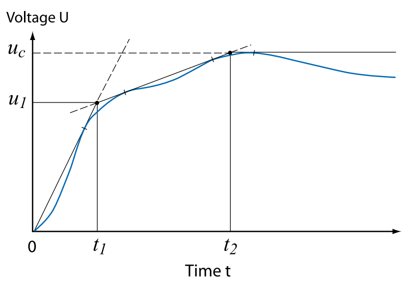


Figure 3.8b TRV with 4-parameter reference line

3.2.2 TRV in three-phase networks

In a three-phase network, several types of short-circuits may occur: single-phase to earth; two-phase, with or without earth connection; and three-phase, with or without earth connection. Three-phase short-circuits are very rare, but lead to the most severe stresses on the circuit breakers. Therefore the TRV voltage values used for type testing are based on three-phase faults. In the network, the three phases will affect each other, and the first phase to interrupt will experience the most severe TRV stress. To compensate for that, a first-pole-to-clear factor is introduced.

Consider the three-phase circuit shown in Figure 3.9. It is a simplified equivalent circuit of a network with effectively earthed neutral, with a three-phase short-circuit. The short-circuit point is isolated, i.e. has no connection to earth. When the first pole (pole “a” is assumed to be the first pole) interrupts the fault, symmetry is lost and a pure two-phase short-circuit remains, causing the potential of the short-circuit point to shift.

The power frequency recovery voltage $\bar{U}_{ra}$ across the circuit breaker in pole “a” may be written: $\bar{U}_{ra} = \bar{U}_a - \bar{U}_n$

Due to the symmetry of the circuit, the potential of the short-circuit point related to earth, $\bar{U}_n$ will attain a value halfway between $\bar{U}_b$ and $\bar{U}_c$ after interruption of the current in pole a. See the vector diagram in Figure 3.10. The absolute value of the power frequency recovery voltage U_{ra} will then be U_{ra} =1.5U_a i.e. 1.5 times the phase-to-neutral voltage.

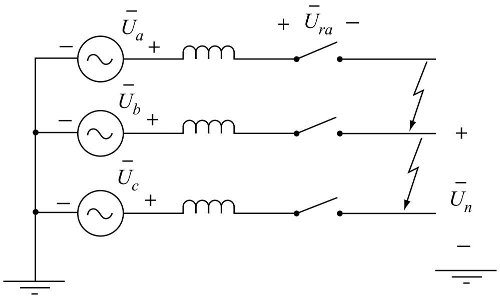


Figure 3.9 Equivalent circuit, isolated three-phase fault in network with effectively earthed neutral

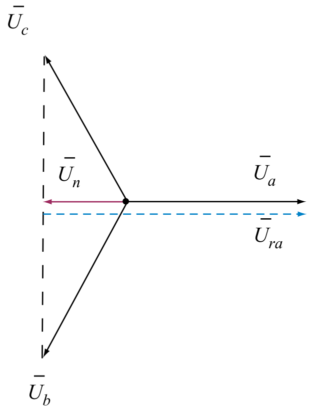


Figure 3.10 Vector diagram

The ratio between the power frequency recovery voltage in the first pole to clear and the phase to earth voltage is the first-pole-to-clear factor:

$$k_{pp} = \frac{U_{ra}}{U_a}$$

The first-pole-to-clear factor k_{pp} depends on the network conditions. For a three-phase earthed fault in a system with non-effectively earthed neutral, or a three-phase unearthed fault in a network with solidly earthed neutral, k_{pp} is equal to 1.5. This is the highest value k_{pp} can attain.

In the quite common case of a three-phase-to-earth fault in a network with earthed neutral, k_{pp} is related to the positive sequence reactance X_1 and zero sequence reactance X_0 of the network as:

$$k_{pp} = \frac{3X_0}{X_1 + 2X_0}$$

The variation of k_{pp} with the system reactance ratio X_1/X_0 is shown in Figure 3.11.

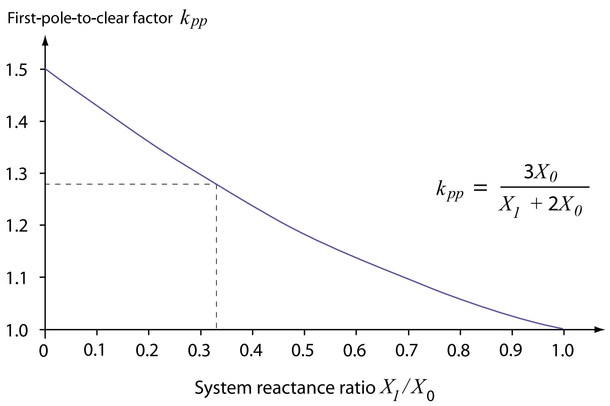


Figure 3.11 Variation of k_{pp} with X_1/X_0

For a normal overhead line, the ratio X_1/X_0 is generally around 1/3. Hence for a network with earthed neutral, in which the reactance is dominated by line reactance, the resulting first-pole-to-clear factor, in the case of an earthed short-circuit, will be of the order of 1.3 (dashed line in Figure 3.11).

IEC 62271-100 is based on the assumption that three-phase faults involve earth (available fault statistics show that this is normally the case). Therefore IEC uses first-pole-to-clear factors to reflect normal practice with regard to system earthing, with k_{pp} = 1.5 for non-effectively earthed and k_{pp} = 1.3 for effectively earthed neutral systems:

Rated voltage U	First-pole-to-clear factor (kpp)
U ≤ 72.5 kV	1.5
72.5 < U ≤ 170 kV	1.3 or 1.5
U ≥ 245 kV	1.3

Table 3.12 First-pole-to-clear factors according to IEC

Basically the IEEE standards specify the same first-pole-to-clear factors as IEC. In addition, however, IEEE takes into consideration the small possibility that isolated three-phase faults may occur. Therefore, as an option, a first-pole-to-clear factor k_{pp} = 1.5 is specified for rated voltages of 100 kV and above.

3.3 Short-line faults

Short-line faults (SLF) are short-circuits that occur on an overhead transmission line within a relatively short distance (some kilometers) from the substation. The fault current is determined not only by the source impedance (network) but also by the impedance of the line between the circuit breaker and the fault location. The TRV in this case is characterized by the propagation of traveling waves along the line, between the circuit breaker and the fault location.

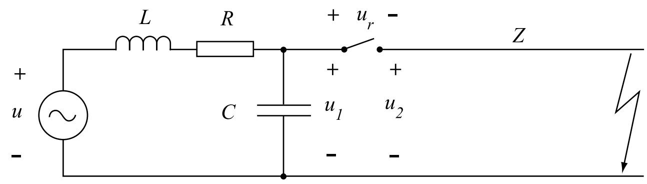


Figure 3.13 Short-line fault in single-phase equivalent circuit

Consider Figure 3.13, which shows a short-line fault in a single-phase equivalent circuit. The supply side has been modeled in the same way as in Figure 3.5. On the load side there is now a certain length of overhead line, characterized by its surge impedance Z, between the fault location and the circuit breaker.

The TRV at interruption of the current in this circuit may be obtained as the difference between the supply and load side voltages:

$$u_r = u_1 - u_2$$

Up to the moment of current interruption, u_1 and u_2 will be practically equal. After interruption, u_1 will approach the power frequency voltage of the system in an oscillatory manner in the same way as at a terminal fault. The voltage u_2 on the load side will approach zero through a damped saw-tooth oscillation, associated with voltage waves traveling on the section of line between the circuit breaker and the fault location.

As shown in Figure 3.14, the transient recovery voltage u_r across the circuit breaker will have the same shape as that of a terminal fault, but with a superimposed saw-tooth oscillation in the initial part, directly after current zero.

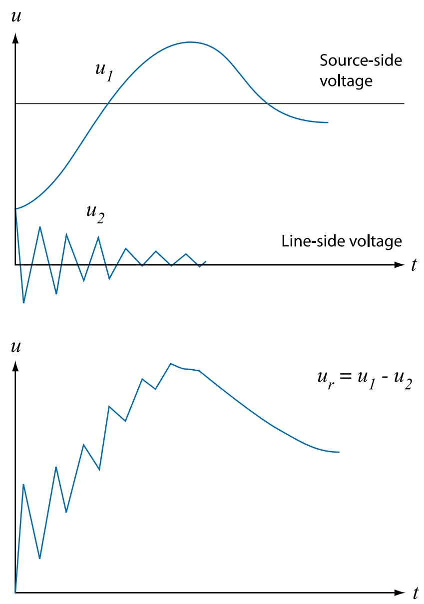


Figure 3.14 The transient recovery voltage for a short-line fault

The rate-of-rise of the saw-tooth voltage on the line side, du_2/dt is directly proportional to the rate-of-decay di/dt of the current immediately before current zero and the equivalent surge impedance Z of the line:

$$\left(\frac{du_2}{dt}\right)_{t=0} = Z\left(\frac{di}{dt}\right)_{t=0}$$

where $di/dt = 2\pi f\hat{I}$, with f = power frequency and $\hat{I}$ = short-line fault peak current. Both IEC and IEEE apply a standard value Z = 450 Ω at all rated voltages.

The fact that the fault occurs relatively close to the circuit breaker means that the SLF current is almost as high as the terminal fault current. Since the rate-of-rise of the TRV is more severe than at a corresponding terminal fault, the major stresses on the circuit breaker are in the thermal regime (refer to Section 2.4.2.1). Increasing the current at a short-line fault thus rapidly increases the stresses on the circuit breaker at current zero, since both di/dt and du_2/dt will be higher, requiring more efficient cooling of the arc region. The most critical conditions will be obtained for a specific line length. With a very short line, the current will be high, but the first peak of the saw-tooth oscillation will be low. Therefore the stresses at current zero will resemble those of a terminal fault. For long line lengths, the current will be decreased so much that it will again be easier for the circuit breaker to clear.

The time t to the first peak of the saw-tooth oscillation is related to the length of the line between the circuit breaker and the fault location. Since the propagation speed of the waves is equal to the speed of light (300 m/μs), a typical line length of 1 km

will give a time of the order of 6 or 7 μs (the time for the wave to travel to the fault location and back again).

Theoretically, the reflected waves exhibit themselves as a pure saw-tooth wave shape, as presented in Figure 3.14. However, the relatively high concentration of stray capacitances at the line end in the substation introduced by instrument transformers, bushings of adjacent equipment, support insulators, etc. generates an initial time delay in the line side voltage oscillation.

IEC specifies SLF requirements for circuit breakers rated 52 kV and above, having a rated short-circuit breaking current exceeding 12.5 kA. In addition, SLF is a requirement for medium-voltage circuit breakers intended for direct connection to overhead lines (Class S2). IEEE has the same requirements. The test requirements in both standards are based on single-phase-to-earth faults.

3.4 Initial Transient Recovery Voltage (ITRV)

A TRV stress similar to that which occurs at a short-line fault may occur, due to the busbar connections on the supply side of the circuit breaker. This TRV stress is referred to as the Initial Transient Recovery Voltage, or ITRV.

Due to the relatively short distances involved, the time to the first peak will be short, typically less than 1 μs. The surge impedance of the busbar in a station is lower than that observed for overhead lines. Both IEEE and IEC apply a value of Z = 260 Ω for air-insulated substations (AIS). For GIS substations the surge impedance is lower, and therefore the ITRV stresses can be neglected.

Figure 3.15 shows the origin of the various contributions to the total recovery voltage for terminal faults and short-line faults. At the source side of the circuit breaker the TRV is generated by the supply network, whereas the substation topology, mainly the busbars, generates the ITRV oscillation. For any fault occurring at the load side of the circuit breaker, both TRV and ITRV will be present in the recovery voltage. For a short-line fault, the total recovery voltage comprises three components: the TRV (network), the ITRV (substation) and the line oscillation.

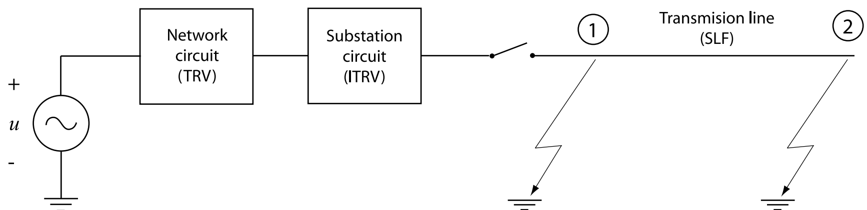


Figure 3.15 Simplified diagram showing the origin of the ITRV and the TRV for terminal fault (1), and for short-line fault (2)

3.5 Out-of-phase conditions

Two cases in which out-of-phase conditions may occur are shown in Figure 3.16. One case occurs when a generator is accidentally switched on to the network at the wrong phase angle (Figure 3.16a). The other case occurs when different parts of a transmission network lose their synchronism, e.g. due to a short-circuit somewhere in the network (Figure 3.16b). In both cases, an out-of-phase current will flow in the networks and will have to be interrupted by the circuit breaker.

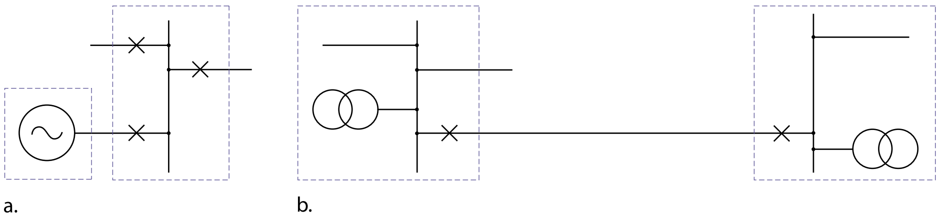


Figure 3.16a and 3.16b Out-of-phase conditions

Considering a single phase, and assuming effectively earthed neutral, both networks in Figure 3.16 may be simplified to the circuit shown in Figure 3.17. The reactances X_1 and X_2 may be obtained from the short-circuit power of the two parts of the network, one on each side of the circuit breaker.

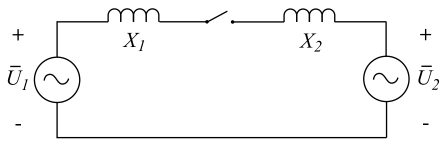


Figure 3.17 Single-phase equivalent network

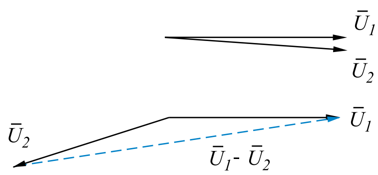


Figure 3.18 Orientation of voltage vectors

In normal operation, the two voltage vectors $\bar{U}1$ and $\bar{U}2$ will be approximately equal in both amplitude and phase angle. Under the most severe out-of-phase conditions, the voltage vectors may be separated 180 electrical degrees. The corresponding maximum power frequency recovery voltage U_r will be $U_r = 2U$, under the assumption that $U_1 = U_2 = U$. In a corresponding case with non-effectively earthed neutral, the power frequency recovery voltage may, in the worst case, reach the value $U_r = 3U$.

Both IEC and IEEE specify tests at $2U$ for effectively earthed neutral systems, whereas it has been considered sufficient to use $2.5U$ for non-effectively earthed neutral systems. Due to the strong damping caused by overhead lines, the amplitude factor of the TRV for out-of-phase switching is generally lower than the amplitude factor at interruption of terminal fault current. An amplitude factor 1.25 is specified. Overall the peak of the TRV for out-of-phase switching is higher than that for interruption of short-circuit current, and leads to severe dielectric stress on the circuit breaker.

The current in this switching case is lower than that observed at interruption of short-circuit current in the network, due to the relatively high impedance of the loop between the two voltage sources (reactance $X_1 + X_2$). Both the IEC and IEEE standards specify that circuit breakers shall be tested at 25% of the rated short-circuit breaking current. Higher current values have been considered highly improbable.

3.6 Switching of capacitive currents

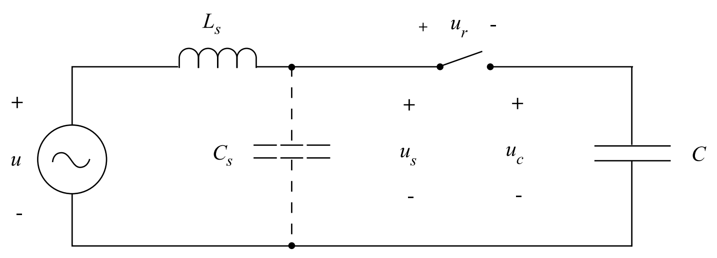
Capacitive currents are encountered in the following cases:
– switching of no-load overhead lines
– switching of no-load cables
– switching of capacitor banks
– switching of filter banks

Interruption of capacitive currents is generally an easy duty for a circuit breaker, because the currents are normally small, perhaps a few hundred amperes. There is, however, a risk that restrikes will occur, which may lead to undesirable overvoltages in the network.

Energizing of capacitive loads may also lead to overvoltages or high currents.

3.6.1 De-energizing of capacitive loads

For a single-phase case, the equivalent circuit shown in Figure 3.19 may be used to illustrate the conditions when de-energizing a capacitor bank. Figure 3.20 shows the current and voltage shapes at interruption.



C	Capacitive load (capacitor bank)	u_s	Source side voltage
u_r	Voltage across the circuit breaker	L_s	Source side inductance
u_c	Voltage across the capacitor bank	C_s	Source side capacitance

Figure 3.19 Single-phase equivalent circuit for capacitive current interruption

With the purely capacitive load, the current will be 90 electrical degrees leading relative to the voltage. This means that when the current is interrupted at a current zero, the voltage will be at its maximum value. After interruption of the current, the supply side voltage u_s will be more or less unaffected. There is only a minor decrease in amplitude, associated with the disappearance of the capacitive load. The transition to the new amplitude value is associated with a slight oscillation, the frequency of which is determined by L_s and C_s. From the moment the current is interrupted, the capacitor C is isolated from the rest of the network. In a short time perspective, the voltage u_c will therefore remain constant at the value it had at current zero, i.e. the peak value of the supply voltage. (In a longer time perspective, the capacitor will gradually discharge. There are generally built-in discharge resistors in capacitor units.)

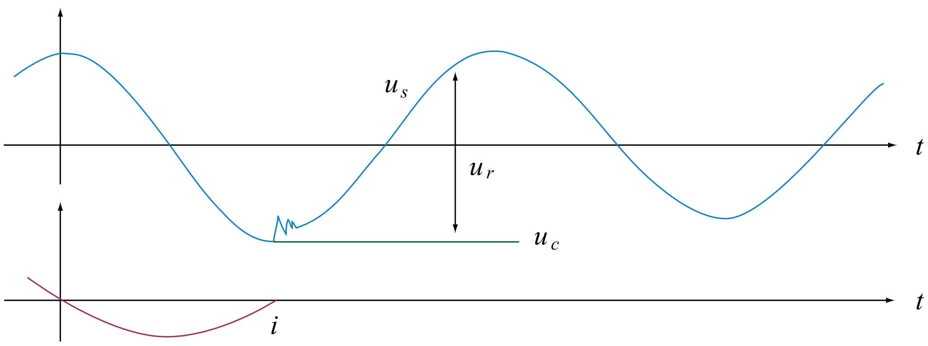


Figure 3.20 Voltage and current shapes at capacitive current interruption

The low initial rate-of-rise of the recovery voltage, together with the low current to be interrupted, makes it extremely easy for the circuit breaker to interrupt. Even if a current zero occurs closely after contact separation, the circuit breaker will interrupt. Half a cycle after current zero, the recovery voltage has risen to no less than twice the peak value of the supply voltage. The circuit breaker may then not be able to withstand the high value of the recovery voltage across a still relatively small contact gap. In this case, dielectric breakdown will occur between the contacts, and current will start to flow again.

Figure 3.21 shows current and voltage wave-shapes in a case where voltage breakdown occurs relatively close to the recovery voltage peak. The load side voltage will swing up to a voltage that ideally (without any damping) may reach 3 times the supply voltage peak U_p. The oscillation frequency of the current and voltage after the breakdown is determined by L_s and C (assuming $C >> C_s$). The circuit breaker may easily interrupt the current again at one of its current zeros, with the result that the voltage across the capacitor may attain a new constant value, perhaps higher than before. Further breakdowns associated with even higher overvoltages across the load may then occur. If a circuit breaker does not interrupt at any of these high-frequency current zeros, it will in any case interrupt at the next power frequency current zero.

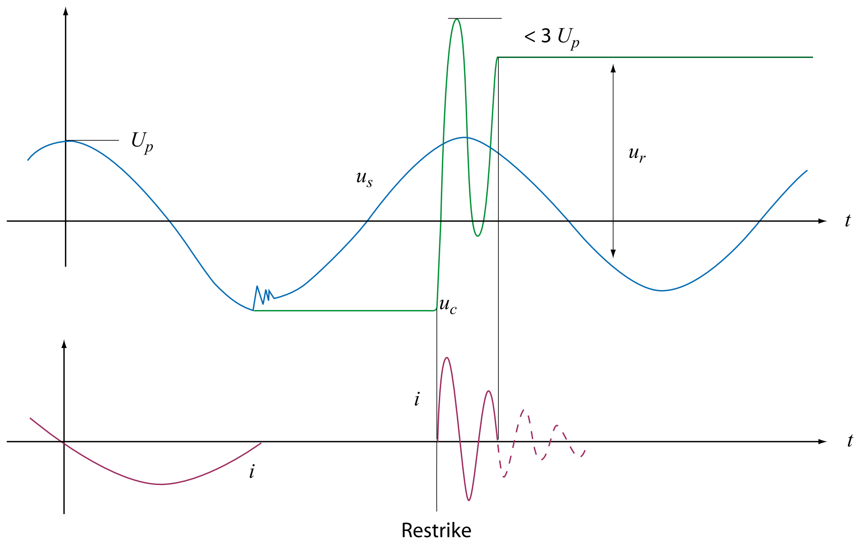


Figure 3.21 Voltage and current wave-shapes in the case of a restrike

Voltage breakdowns during capacitive current interruption are divided into two categories:

Reignitions:	Voltage breakdown during the first 1/4 cycle following current interruption.
Restrikes:	Voltage breakdown 1/4 of a cycle or more following current interruption.

Restrikes will lead to overvoltages across the capacitive load (maximum 3 p.u. for a single restrike, where 1 p.u. is the peak value of the phase-to-earth voltage), while reignitions will not produce any overvoltages (theoretically max. 1 p.u.).

A properly-designed circuit breaker should not produce restrikes. The phenomenon is statistical, however, and both IEC and IEEE define two different classes of circuit breakers:

Class C1:	Circuit breaker with low probability of restrike during capacitive current breaking as demonstrated by specific type tests.
Class C2:	Circuit breaker with very low probability of restrike during capacitive current breaking as demonstrated by specific type tests.

The type tests for Class C1 are performed on a circuit breaker with new contacts, and with a number of breaking operations with capacitive current at various arcing times. The corresponding type tests for Class C2 are performed on a circuit breaker that has been previously aged by means of short-circuit switching operations, and consist of a higher number of breaking operations than for Class C1.

3.6.2 Recovery voltage

In a three-phase circuit, the recovery voltage will have a more complicated shape than in a corresponding single-phase situation. It will be most severe in the first-pole-to-clear, and in the majority of cases be higher than in the single-phase case. Figure 3.22 shows as an example the recovery voltage of the first-pole-to-clear when de-energizing a capacitor bank with isolated neutral. The recovery voltage initially has a shape that would lead to a peak value equal to three times the supply voltage peak (dotted line). When the last two poles interrupt 1/4 cycle (90 electrical degrees) after the first, there is, however, a discontinuity in the slope, and the final peak value for the first pole-to-clear is limited to 2.5 times the supply voltage peak.

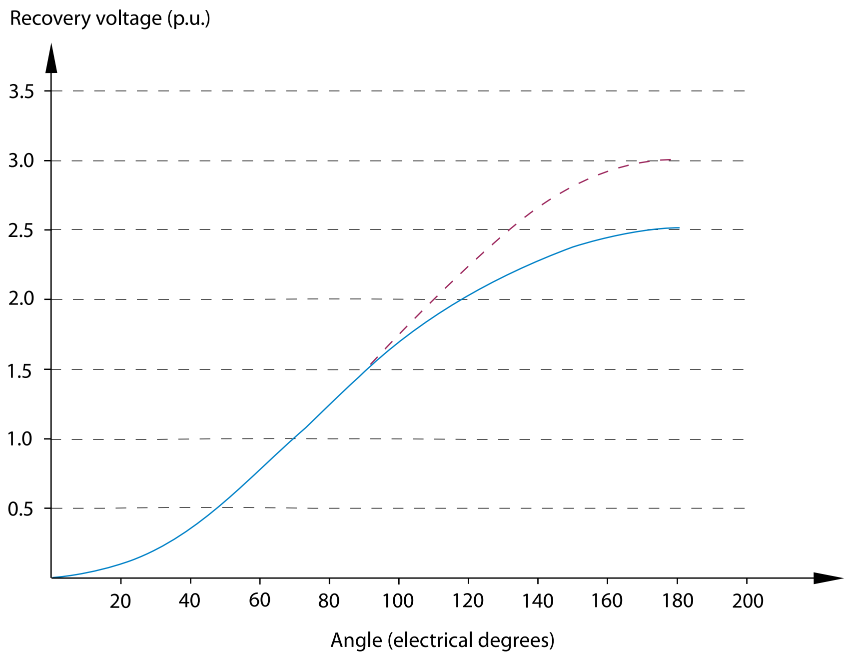


Figure 3.22 Recovery voltage in the first-pole-to-clear at interruption of capacitor bank with isolated neutral.

The IEC and IEEE standards specify capacitive voltage factors for different types of capacitive load. The capacitive voltage factor is used for calculation of the relevant test voltage in a single-phase test circuit intended to simulate the conditions in the first-pole-to-clear of a three-phase network.

Standard values for capacitive voltage factors, k_c, for normal service conditions are as follows:

No-load line switching	
k_c = 1.2	Effectively earthed neutral
k_c = 1.4	Non-effectively earthed neutral

No-load cable switching	
k_c = 1.0	Screened cables in systems with solidly earthed neutral
k_c = 1.2	Belted cables in systems with effectively earthed neutral
k_c = 1.4	In systems with non-effectively earthed neutral

Capacitor bank switching	
k_c = 1.0	Capacitor bank with earthed neutral in systems with solidly earthed neutral
k_c = 1.4	Capacitor bank with isolated neutral

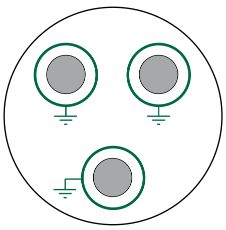


Figure 3.23a Screened cable

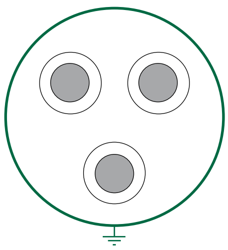


Figure 3.23b Belted cable

3.6.3 Energizing of capacitor banks

Energizing of capacitive loads is usually associated with transient voltages and currents. This section covers the phenomena associated with energizing of capacitor banks.

Given the increasing use of capacitor banks for compensation purposes, it is common that more than one capacitor bank is connected to the same busbar. This has no influence on the conditions at interruption. The current at closing, however, is affected to a high degree. With one or more capacitor banks already connected, there will be an inrush current when closing a circuit breaker to connect an additional bank (so-called back-to-back switching). This inrush current may have a very high amplitude and frequency, and will sometimes have to be limited in order to not harm the circuit breaker, the capacitor banks and/or the network.

The single-phase equivalent of a circuit where two capacitor banks are connected to a busbar is shown in Figure 3.24. The inductances L_1 and L_2 represent the stray inductance (or stray inductance plus additional damping inductance). The inductance L_s of the supply network will be several orders of magnitude higher than L_1 and L_2.

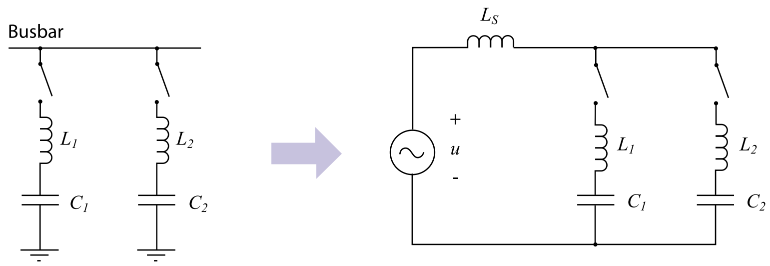


Figure 3.24 Parallel capacitor banks

The case of energizing a single capacitor bank is equal to energizing of C_1 when C_2 is not connected in the circuit described in Figure 3.24. The circuit then consists of the source inductance L_s in series with the capacitor bank C_1. The inductance L_1 can be disregarded here, since $L_s >> L_1$. In this case, the peak of the inrush current i_{peak} and inrush current frequency f_i are limited by the source impedance L_s.

Assuming that bank C_1 is to be connected to the busbar and bank C_2 is not connected, the following equations apply. The highest inrush current peak is obtained when energizing the capacitor bank at the peak of the supply voltage:

$$i_{peak} = \hat{u}\sqrt{\frac{C_1}{L_s}}\sin\omega t \qquad \text{and} \qquad f_i = \frac{1}{2\pi\sqrt{(L_s + L_1)C_1}}$$

with $L_s >> L_1$, the frequency of the inrush current, is:

$$f_i = \frac{1}{2\pi\sqrt{L_s C_1}}$$

If bank C_1 is connected to the busbar and bank C_2 is to be connected, the inrush current associated with the charging of bank C_2 is supplied by bank C_1 (back-to-back switching). The peak and frequency of the inrush current are now limited by L_1 and L_2:

$$i_{peak} = \hat{u}\sqrt{\frac{C_r}{L_r}}\sin\omega t$$

with $$C_r = \frac{C_1 C_2}{C_1 + C_2} \qquad \text{and} \qquad L_r = L_1 + L_2$$

The frequency of the inrush current is now:

$$f_i = \frac{1}{2\pi\sqrt{L_r C_r}}$$

The same equations may be applied in a three-phase case. The voltage $\hat{u}$ is then the peak value of the phase-to-earth voltage.

Typical amplitudes of the inrush currents for back-to-back energizing of capacitor banks are several kA, with frequencies of 2 - 5 kHz. Capacitor banks can normally withstand amplitudes up to 100 times their rated normal current. For circuit breakers, IEC suggests 20 kA peak at 4.25 kHz as standard withstand capability.

Controlled switching is an attractive and well-proven means of limiting the inrush current amplitude and associated stresses on the equipment. See ABB Controlled Switching, Buyer's and Application Guide 1HSM 9543 22-01en. In addition, the inrush current amplitude and frequency can be decreased by insertion of additional series inductance in the circuit.

3.7 Inductive load switching

Inductive load switching will occur in the following cases:
- switching of shunt reactors
- switching of unloaded transformers

The currents to be interrupted are low compared to the short-circuit current, and range from a few amperes to some hundred amperes. Therefore, they are often referred to as "small inductive currents." After opening of the circuit breaker, the current flows through the arc between the contacts. This arc is stable at high currents, but becomes unstable at low currents in the order of 5 - 10 A, and is usually forced to a premature current zero. This phenomenon of current interruption prior to the natural current zero is usually referred to as current chopping. The resulting chopping overvoltages, and particularly overvoltages due to subsequent reignitions, may be a concern. Controlled switching of the circuit breaker is an efficient way to eliminate the reignition overvoltages. See ABB Controlled Switching, Buyer's and Application Guide.

3.7.1 Switching of shunt reactors

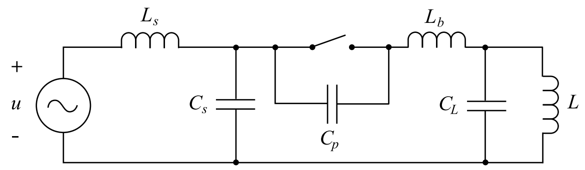
The most clear-cut case of inductive load switching is the interruption of a reactor current. The reactor may be directly connected to the network (shunt reactor) or through a transformer (e.g. connected to a tertiary winding). In both cases the load consists of an approximately linear inductance.

A three-phase shunt reactor configuration may differ considerably. The following configurations exist:
- a bank of single-phase reactors
- a three-phase unit with a 3-legged core
- a three-phase unit with a 5-legged core
- a three-phase unit of the shell type

The earthing conditions also may vary:
- solidly earthed neutral
- earthing through a neutral reactor
- isolated neutral

3.7.1.1 Current chopping and resulting overvoltages

Due to the variety of cases, the treatment of interruption of reactor current is complex. For this reason, the relatively simple single-phase circuit shown in Figure 3.25 depicts only one such case. This case is applicable for shunt reactors with directly earthed neutral and negligible interaction between phases.



L_s	Source inductance	L_b	Connection series inductance
C_s	Source side capacitance	C_L	Load side capacitance
C_p	Parallel capacitance	L	Reactor inductance

Figure 3.25 Single-phase equivalent circuit for shunt reactor switching

Assuming that the current is chopped at an instantaneous value I_{ch}, there is a magnetic energy W_m stored in the load inductance at the moment of interruption:

$$W_m = \frac{1}{2} L I_{ch}^2$$

With $C_s >> C_p$, which is normally the case, the total capacitance on the reactor side of the circuit breaker C_t is approximately

$$C_t = C_L + C_p$$

The voltage across the reactor at the instant of interruption is approximately equal to the peak U_p of the source side phase-to-earth voltage, and is determined by the system voltage U (assumed equal to the rated voltage of the reactor):

$$U_p = \frac{U\sqrt{2}}{\sqrt{3}}$$

Therefore the capacitance C_t will be charged to the energy:

$$W_0 = \frac{1}{2} C_t U_p^2$$

After interruption, the energy stored in the inductance and capacitance swings back and forth between the inductance and the capacitance. After some time the energy will decrease due to the losses in the circuit. When all the energy, W_c, is stored in the capacitance, the voltage across the reactor will reach its highest value U_m. This value is called the suppression peak overvoltage:

$$W_c = \frac{1}{2} C_t U_m^2$$

$$W_c = W_0 + W_m \Rightarrow \frac{1}{2} C_t U_p^2 + \frac{1}{2} L I_{ch}^2 \Rightarrow U_m = \sqrt{U_p^2 + \frac{L I_{ch}^2}{C_t}}$$

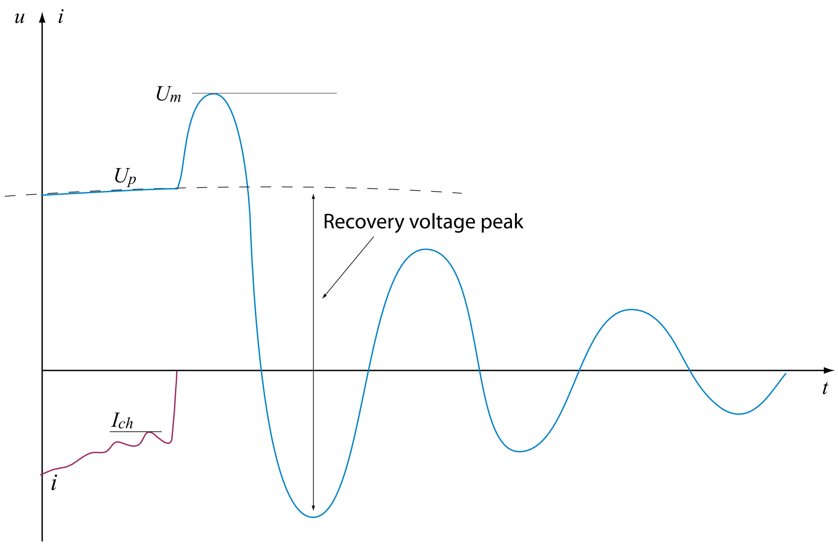


Figure 3.26 Voltage across the reactor at interruption

The frequency of the oscillation is of the order of some 1 to 5 kHz at high voltages and is determined by the natural frequency of the reactor load circuit, i.e. the reactor itself and all equipment connected between the circuit breaker and the reactor.

It is convenient to express the suppression peak overvoltage U_m as an overvoltage factor k_a:

$$k_a = \frac{U_m}{U_p} = \sqrt{1 + \frac{L I_{ch}^2}{C_t U_p^2}}$$

The overvoltage is not only dependent on the type of circuit breaker, but also on the total capacitance C_b in parallel with the circuit breaker. It can be shown that for air-blast, oil and SF_6 circuit breakers, the chopping current is given by the relation

$$I_{ch} = \lambda \sqrt{C_b} \approx \lambda \sqrt{C_t}$$

where λ is called chopping number. The capacitance C_b is the capacitance seen from the circuit breaker's terminals. It is approximately equal to C_t provided that $C_s >> C_L$, which is normally the case.

The chopping number λ, is a characteristic of the circuit breaker and can be assumed to be a constant for different types of circuit breakers, except for vacuum circuit breakers. Ranges of typical chopping numbers are given in Table 3.1.

Circuit breaker types	Chopping number (λ) ($AF^{0.5}$)
Minimum oil	$7\text{-}10 \times 10^4$
Air blast	$15\text{-}25 \times 10^4$
SF_6	$4\text{-}17 \times 10^4$

Table 3.1 Circuit breaker chopping numbers

The chopping number λ applies to circuit breakers with a single interrupter per pole. For circuit breakers with N interrupters per pole, the following expression applies:

$$i_{ch} = \lambda \sqrt{N C_t}$$

The overvoltage factor depends on the chopping number and on the rating of the shunt reactor. With a three-phase reactive power rating Q and angular frequency $\omega = 2\pi f$, the inductance per phase of the reactor will be

$$L = \frac{U^2}{\omega Q}$$

As a result, the overvoltage factor k_a can be written

$$k_a = \sqrt{1 + \frac{1.5 N \lambda^2}{\omega Q}}$$

3.7.1.2 Reignitions

After interruption, the circuit breaker is stressed by the difference between the supply side voltage (which is close to the crest of the power frequency voltage) and the load side oscillating voltage. A first peak of the recovery voltage occurs at the same time as the suppression overvoltage peak of the voltage across the reactor. A second, higher peak of the recovery voltages occurs half an oscillation cycle later. See Figure 3.26. At the second recovery voltage peak, the circuit breaker is stressed by a voltage that may approach the suppression overvoltage plus the peak of the source side voltage. If the circuit breaker does not reignite before or at this point, then the interruption is successful. If, however, the instant of contact parting is such that the contact gap does not yet have sufficient dielectric strength, then a reignition will occur. A reignition will generate high-frequency transients, typically hundreds of kHz, in both the reactor voltage and the current through the circuit breaker.

All circuit breakers will reignite when the interruption occurs with a small contact distance, i.e. after a short arcing time. The range of arcing times in which this occurs may be narrow or wide, depending on the rate of rise of voltage withstand capability of the circuit breaker (which depends on the interrupting medium, contact velocity, electrode design, etc). If the high frequency current through the circuit breaker resulting from a reignition is interrupted again, a new recovery voltage starts to build up, which may lead to further reignitions and gradually increasing overvoltages. Such a case, with three consecutive reignitions, is shown in Figure 3.27.

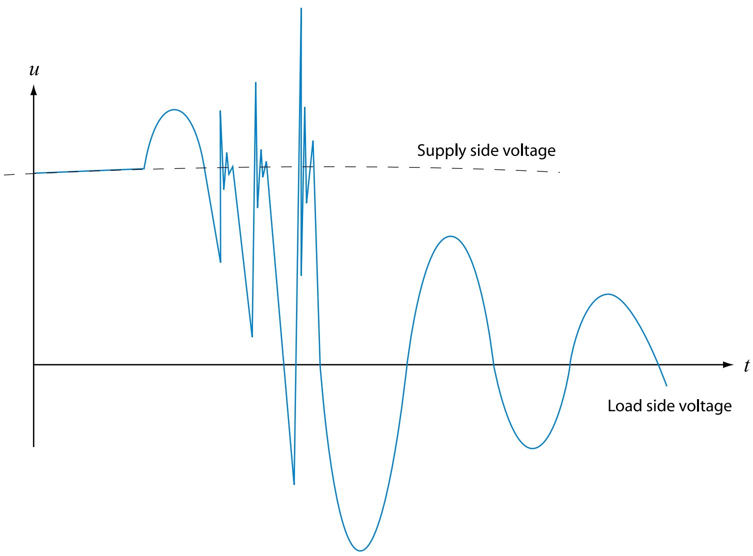


Figure 3.27 Reignition phenomena in a singe-phase circuit

3.7.1.3 Overvoltages and overvoltage limitation

The stress on the reactor due to current chopping is determined by the highest peak voltage to earth, which is normally the suppression peak overvoltage. Due to the comparatively low frequency, the overvoltage is evenly distributed across the winding, which results in low interturn voltages in the reactor winding. In most cases these chopping overvoltages are relatively low, and therefore acceptable. An exception may be cases with small reactors (low Mvar ratings).

When a reignition occurs, the load side voltage rapidly tends toward the source side voltage, but overshoots and produces a reignition overvoltage. Figure 3.28 shows the maximum attainable overvoltages without damping for a reignition at the recovery voltage peak. In practical cases there will always be damping of the oscillations, leading to lower maximum overvoltages. The voltage breakdown at a reignition creates a steep voltage transient that is imposed on the reactor. The front time varies from less than 1 μs to several μs. Since the voltage breakdown in the circuit breaker is practically instantaneous, the steepness is determined solely by the frequency of the second parallel oscillation circuit (circuit consisting of C_L, C_s and L_b in Figure 3.25), which in its turn depends on the circuit layout. This steep transient may be unevenly distributed across the reactor winding, stressing the entrance turns in particular with high interturn overvoltages.

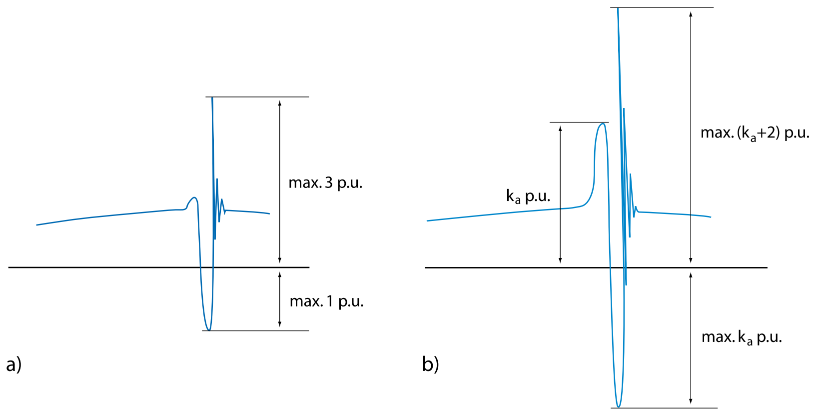


Figure 3.28 Reignition overvoltages in cases with negligible current chopping (a), and with high current chopping (b).

Shunt reactors are normally protected by surge arresters. These arresters will limit overvoltages to earth to acceptable levels, but cannot reduce the steepness of the voltage swings associated with reignitions.

Reignitions in modern circuit breakers can be eliminated using controlled opening of the circuit breaker. The controlling device allows point-on-wave switching so that short arcing times will not occur, thus preventing reignitions. See ABB Controlled Switching, Buyer's and Application Guide.

3.7.2 Switching of no-load transformers

The interruption of a no-load current of a transformer also means interruption of low inductive currents. It is usually regarded as an easy switching case and has little tendency to cause overvoltage problems. The current level is very low, generally less than 10 A. The voltage oscillation across the transformer after interruption is strongly damped, and normally has a natural frequency of no more than a few hundred Hz.

4. Mechanical stresses and environmental effects

The correct function of a circuit breaker is dependent on its mechanical properties. By mechanical properties, we mean the circuit breaker's capability to withstand external and internal mechanical loads. The circuit breaker also has to function correctly under a variety of environmental conditions. Another important mechanical issue is the circuit breaker operational forces that act on the foundation during operation.

4.1 Mechanical loads

A number of mechanical loads act upon the circuit breaker: static loads (dead weight, terminal load, ice), forces caused by operation, current switching and forces from harsh environmental conditions such as wind and earthquakes. Some of these loads act together (e.g. terminal load and dead weight), while other loads are more rare in their occurrence (e.g. earthquake loads).

4.1.1 Static loads

4.1.1.1 Dead weight

The dead weight of the circuit breaker and its structure acts as a load on the foundation. These factors must always be taken into consideration during preparation of the installation site and when dimensioning the foundations.

4.1.1.2 Static terminal load

Static terminal loads are stresses from ice layers, wind and the connected conductors. These loads cause a bending moment that stresses the circuit breaker support insulator, frame and foundation. Even though the wind can vary dynamically, IEC specifies that it shall be taken into consideration as a static load.

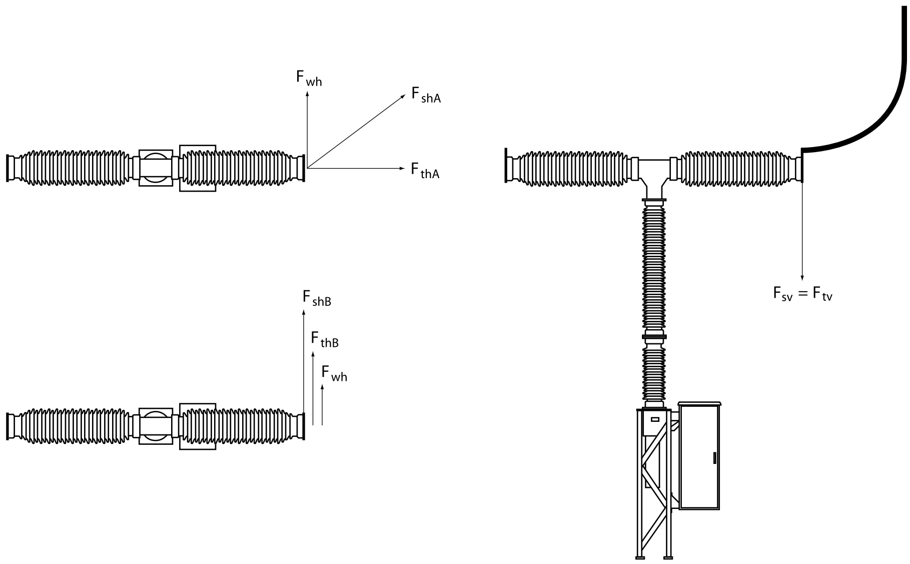
Some examples of forces due to flexible and tubular conductors (not including wind, ice loads or dynamic loads on the circuit breaker) are given as a guide in IEC 62271-100, 6.101.6, see Table 4.1.

Rated voltage range	Rated current range	Static horizontal force F_{th}		Static vertical force (vertical axis-upward and downward)
		Longitudinal	Transversal	
U_r	I_r	F_{thA}	F_{thB}	F_{tv}
kV	A	N	N	N
52 - 72.5	800 - 1250	500	400	500
52 - 72.5	1600 - 2500	750	500	750
100 - 170	1250 - 2000	1000	750	750
100 - 170	2500 - 4000	1250	750	1000
245 - 362	1600 - 4000	1250	1000	1250
420 - 800	2000 - 4000	1750	1250	1500

For the directions of $F_{thA,B}$ and F_{tv} see Figure 4.1

Table 4.1 Forces due to flexible and tubular conductors

The rated static terminal loads, F_{shA}, F_{shB} and F_{sv}, see Figure 4.1, are the resultant of simultaneous acting loads from ice, wind and connected conductors. Calculations or tests must be performed by the manufacturer to verify that the equipment has been dimensioned to handle these terminal loads with maintained functionality.



F_{thA}	Tensile horizontal force due to connected conductors, direction A
F_{thB}	Tensile horizontal force due to connected conductors, direction B
F_{tv}	Tensile vertical force due to connected conductors
F_{wh}	Horizontal force on circuit breaker due to wind pressure on ice-coated circuit breaker
F_{shA}, F_{shB} , F_{sv}	Rated static terminal load (resultant forces)

Figure 4.1 Terminal loads according to IEC

	Horizontal	Vertical	Remark
Forces due to dead weight, wind and ice on connected conductor	F_{thA}, F_{thB}	F_{tv}	According to Table 4.1
Forces due to wind and ice on circuit breaker*	F_{wh}	0	Calculated by manufacturer
Resultant force	F_{shA}, F_{shB}	F_{sv}	

* The horizontal force on the circuit breaker, due to wind, may be moved from the centre of pressure to the terminal and reduced in magnitude in proportion to the longer lever arm. (The bending moment at the lowest part of the circuit breaker should be the same.)

Table 4.2 Static terminal loads

4.1.1.3 Ice load

When high voltage apparatus are subjected to cold climates, ice will sometimes build up in layers on the surfaces. When the equipment is dimensioned, the added loads due to the ice must be taken into consideration.

Example:
A layer of 20 mm ice on a 245 kV circuit breaker adds approximately 150 kg to the mass of each phase.

IEC 62271-1 specifies that ice coating shall be considered in the range from 1 mm up to, but not exceeding, 20 mm; often an ice coating of 1, 10 or 20 mm is specified.

When exposed to ice load, it should be possible to operate the circuit breaker without impairing its function. Generally circuit breakers have moving parts protected from these ice layers and have no problem operating under these conditions.

Modern integrated solutions such as withdrawable or disconnecting circuit breakers with moving trolleys or earthing switches, which have exposed mechanical systems, must be dimensioned to operate without disturbances even when the mechanical arrangements have coatings of ice.

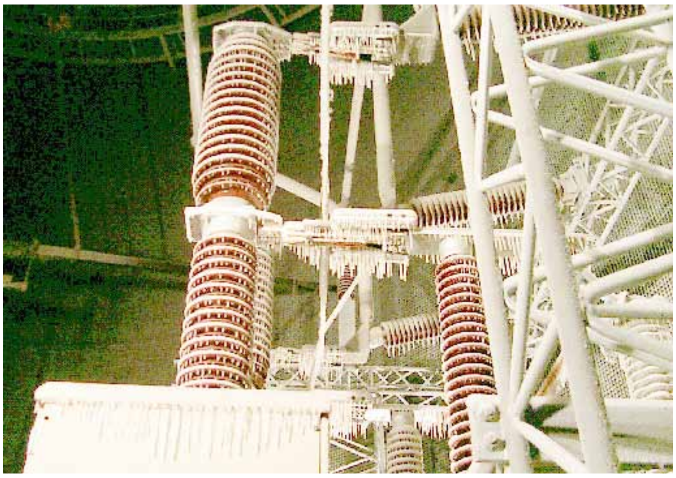


Figure 4.2 Type test of a withdrawable circuit breaker

4.1.1.4 Wind load

Outdoor circuit breakers are exposed to wind loads that will result in a bending moment on the circuit breaker poles and the frames. IEC 62271-1 specifies a maximum wind speed of 34 m/s as the normal service condition.

Example:
For a 245 kV circuit breaker, the resulting wind load (34 m/s) will stress the lowest part of the support structure and foundation with a bending moment of 9,100 Nm. The wind will also affect the conductors, which generates additional bending moment of approximately 650 Nm.

$$F_w = c_w \frac{1}{2} \rho v^2 A$$

where:

F_w	Force on a surface due to wind	N
A	Projected surface area exposed to wind	m^2
ρ	Air density	kg/m^3
v	Wind speed	m/s
c_w	Wind resistance coefficient Approximate values used by ABB HVP: 1.0 for cylindrical surfaces 2.0 for plane surfaces	

Table 4.3 Factors for calculation of wind load

4.1.2 Dynamic loads

4.1.2.1 Dynamic loads due to operation

When a circuit breaker is carrying out closing and opening operations, reaction forces will be generated. These forces are usually of impact and vibrative nature and act on the foundation. The foundation, as well as the anchor bolts and the circuit breaker frame, must be designed to withstand these loads.

The forces vary with the size of the circuit breaker, and the type and energy of the operating mechanism. The values stated by the manufacturer shall be used for dimensioning purposes. As an indication, typical values are given in Table 4.4.

Rated voltage kV	Horizontal force kN	Vertical force kN
123 - 170	1 - 15	10 - 75
245 - 300	5 - 20	25 - 75
362 - 550	10 - 30	50 - 120

Table 4.4 Typical values of operation forces per pole acting on the foundation

4.1.2.2 Dynamic current loads

Parallel current-carrying conductors will exert forces on each other due to the interaction of the magnetic field (see Figure 4.3). This is also the case for the circuit breaker poles. The directions of the forces are dependent on the directions of the currents. The same direction of currents yields repelling forces; opposite directions will yield attracting forces.

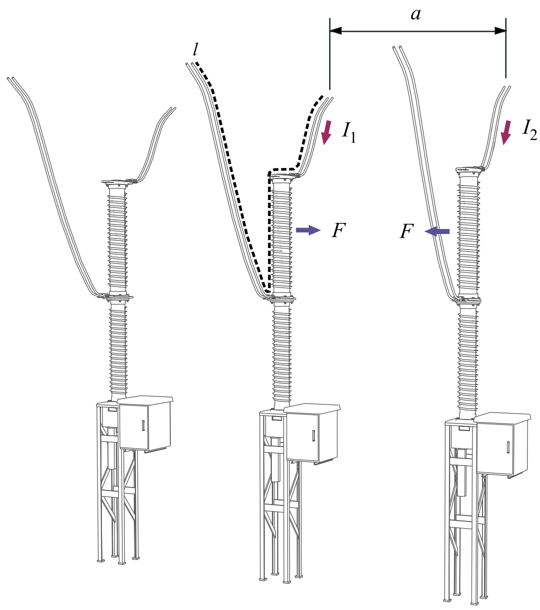


Figure 4.3 Forces between two circuit breaker poles

The maximum force at a three-phase short-circuit acts on the central conductor. Not only should the action between the circuit breaker poles be considered, but also the forces between the connections to the high voltage terminals.

This is a dynamical situation; the peak of the short-circuit will not act on the same time, and the magnitude of the current is different in the three phases. A rough estimation of the force is given by:

$$F_{sc} = 0.2K \frac{I_{k3}^2}{L_{ph}} L_{sc}$$

where:

I_{k3}	Three-phase initial short-circuit current,	kA
K	4.0	
L_i	Length of interrupter	m
L_c	Part of conductor connected to the main terminals of the circuit breaker	m
L_{sc}	Total length, interrupter and connected conductors	m
L_{ph}	Distance between the phases	m
F_{sc}	Electromagnetic forces on equipment	N

Example:
Forces at three-phase short-circuit current for a 245 kV circuit breaker:

- Length of interrupter, L_i 2.0 m
- Length of upper conductor, L_{c1} 1.5 m
- Length of lower conductor, L_{c2} 1.5 m
- $L_{sc} = L_i + L_{c1} + L_{c2}$ = 5.0 m
- Distance between phases, L_{ph} 3.5 m
- Initial three-phase fault current, I_{k3} 50 kA

Inserted in the equation, the resulting force F_{sc} will be 2,857 N.

4.1.3 Seismic load

Users in regions that frequently experience earthquakes usually specify that all equipment installed in the network should be able to operate under, and survive the effects of, earthquake conditions.

Normally the manufacturer uses the data provided by the user to decide if the equipment can meet the requirements, or if any precautions to increase the strength of the designs should be taken.

In order to deliver the correct version of circuit breakers for installation in earthquake areas, the following information should be available from the customer:

- Maximum horizontal and vertical ground acceleration at the installation site, or information about the seismic intensity in accordance with a certain earthquake scale, such as the Richter magnitude.
- Seismic response spectrum or the seismic standards.
- Ground conditions.

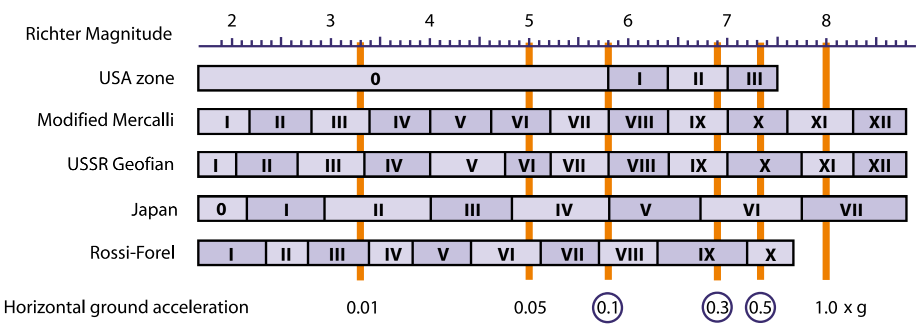


Figure 4.4 Approximate comparison of various earthquake scales and corresponding horizontal ground acceleration

4. Mechanical stresses and environmental effects

The most frequently-applied standards are IEC 61166 and IEEE 693-2005.
The IEC 61166 standard has recently been replaced by IEC 62271-300, but is still referred to in many specifications. For South America, the specification ENDESA ETG1.020 is also important.

In order to verify whether equipment complies with certain seismic requirements, methods for tests or analyses of their combination can be applied.

The tests can be carried out on a shaking table where the seismic acceleration and the displacement are simulated according to the time history method. In the past several other test methods have been specified, such as sine wave and sine beat. Time history testing, according to IEC 60068-2-57, is the only relevant shake table test method, as it is the application of an actual recorded accelerogram (time history signal) or a calculated artificial accelerogram which is satisfying the specified response spectra. The time history testing considers unknown parameters like natural frequencies, damping and non-linearities of the design in an accurate manner.

In order to perform a correct calculation, it is necessary to know the natural frequency of oscillation of the circuit breaker and the damping of oscillation. This can easily be obtained with a snap-back test. During this test, the load is applied (e.g. by applying a pulling force on the terminal), the load is suddenly released and the circuit breaker is left to oscillate freely. By applying strain gauges, a curve as shown in Figure 4.5 can be recorded.

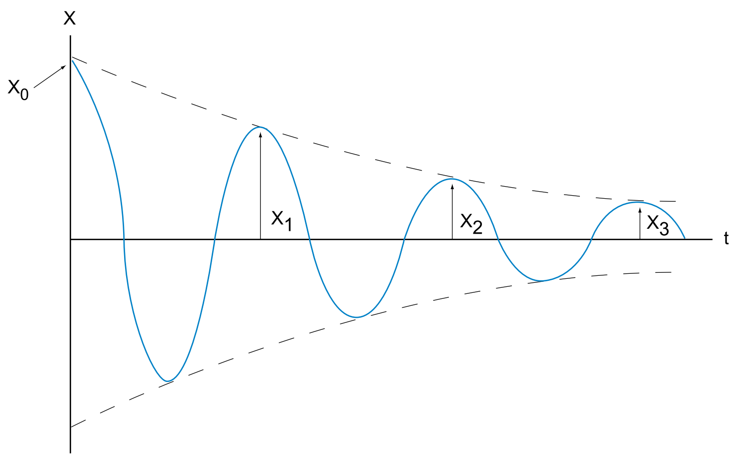


Figure 4.5 Response curve of a snap-back test

The calculations can be carried out by combining the values for mass, dimensions, resonance frequency and damping of the circuit breaker with the response spectra. The results from FEM (Finite Element Method) calculations with input from a snap-back test have shown strong agreement with results from shaking table tests, and are a good and cost-efficient alternative to such tests.

4.1.3.1 Measures to increase seismic withstand levels

If tests or calculations show that the seismic loads are too high for the selected circuit breaker, the design can be reinforced. Reinforcements of the support insulator and/or the mechanical structure are the usual measures taken to increase the strength and the margin against earthquake loads.

As an alternative for large circuit breakers, earthquake dampers can be used. The dampers are mounted between the foundation and the stand of each pole. The natural damping of a circuit breaker is normally around 2%. With the application of dampers, a damping of 20% can be achieved.

Generally live tank circuit breakers can withstand ground accelerations up to 0.2 – 0.3 g in the standard configurations. To fulfill requirements of 0.3 – 0.5 g, reinforcements or dampers must be used.

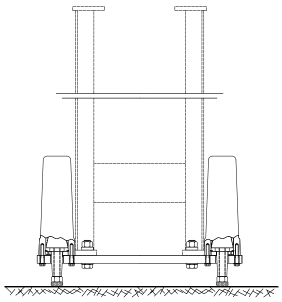


Figure 4.6
Support column of HV circuit breaker with earthquake damping units.

4.2 Combination of loads

The previously-mentioned loads, such as wind, static, dynamic and ice loads, usually act together at the same time. Of course, it is not realistic to have demands on the equipment to withstand high levels of all types of loads at the same time. It is very unlikely that a circuit breaker would be exposed to high wind levels, extreme ice loads and a full short-circuit load, and at the same time have to withstand the stresses from an earthquake.

The following sources in Table 4.5 should be used to determine the loads described in Table 4.6:

Design pressure	Stated by the manufacturer
Mass	Stated by the manufacturer
Terminal loads	6.101.6.1 of IEC 62271-100
Wind loads	6.101.6.1 of IEC 62271-100, 2.1.2 and 2.2.5 of IEC 62271-1
Ice loads	6.101.6.1 of IEC 62271-100 and 2.1.2 of IEC 62271-1
Short-circuit load	Depending on short-circuit current, see also IEC 60865-2
Seismic loads	IEC 62271-300

Table 4.5 Mechanical loads and standards where the loads are specified.

For circuit breakers with ceramic insulators, IEC 62155 states safety factors and gives a recommendation of how to combine these loads (see Table 4.6). For circuit breakers equipped with composite insulators, the loads are derived and combined according to Tables 4.5 and 4.6. IEC 61462 specifies to which level the composite material can be loaded.

Loads	Stress from routinely expected loads	Stress from rarely occurring extreme loads		
		Alternative 1 Short-circuit load	Alternative 2 Ice load	Alternative 3 Seismic load
Design pressure	100%	100%	100%	100%
Mass	100%	100%	100%	100%
Rated terminal load	100%	50%	0%	70%
Wind pressure	30%	100%	0%	10%
Short-circuit load	0%	100%	0%	0%
Ice load	0%	0%	100%	0%
Seismic load	0%	0%	0%	100%
Safety factor	2.1	1.2	1.2	1.0

Table 4.6 Combination of different loads

4.3 Influence of extreme ambient temperatures

For outdoor circuit breakers, IEC specifies the preferred minimum temperature ratings: -10, -25, -30 and -40 °C. The corresponding maximum ambient temperature is +40 °C. Even lower ambient temperature, typically -50 °C, may be specified for very cold climates. For very hot climates, the maximum ambient temperature may be increased to +50 °C. Rapid temperature variations also need to be considered, as well as solar radiation. The solar radiation will, for example, increase the temperature inside the poles and mechanism cubicles.

The proper function of a circuit breaker with regard to extreme ambient temperature is verified at low and high temperature type tests. The opening and closing times of the circuit breaker are measured before, during and after these tests. In addition, any gas leakage is recorded. A certain increase in SF_6 leakage rate is permitted at the extreme ambient temperatures, but after the tests, the leakage rate shall return to the low value recorded before the tests. IEC specifies an annual maximum leakage rate of 0.5% or 1%. (Experience from several high and low temperature tests with ABB HV circuit breakers shows that the normal leakage rate is below 0.1%).

The ambient temperature will have a certain influence on the opening and closing times of a circuit breaker. As a result, there is an influence on the operating precision in controlled switching applications. This influence can be counteracted by use of the adaptive control and temperature compensation features of the synchronized switching controller that is used.

Rapid temperature changes as well as solar radiation may affect the function of SF_6 density monitors. This happens if the temperature of the sensing elements of the monitor differs significantly from that of the SF_6 gas in the circuit breaker. In extreme cases, such temperature differences may even lead to false alarms for low gas density. As a countermeasure, density monitors may be protected from direct sunlight by means of sunshades, or thermally insulated from the surrounding air.

High humidity and the possible occurrence of condensation require proper ventilation of the mechanism cubicles. Operating mechanisms usually have a continuously

connected anti-condensation heater. In addition, one or more controlled heaters may be fitted. These are normally controlled by a thermostat. As an alternative, they may be switched in and out by a humidity (moisture detector) controller.

Additional information about ABB live tank circuit breakers regarding temperature ratings and specified leakage rates can be found in our Buyer's Guides.

4.4 Gas properties

4.4.1 Effect of ambient temperature

The excellent properties of SF_6 (sulfur hexafluoride) gas as a medium for current extinction as well as an insulation medium have been described in Section 2. At very low temperatures, however, the gas will start to condensate. The temperature at which condensation occurs depends on the gas density, and increases with increasing density, see Figure 4.7.

Example:
For a circuit breaker with a rated filling pressure of 0.5 MPa, at 20 °C ambient temperature, the condensation will start at approximately -40 °C, see curve A in the figure.

Gas condensation will reduce the gas density, with the result that the current extinction and insulating properties are reduced.

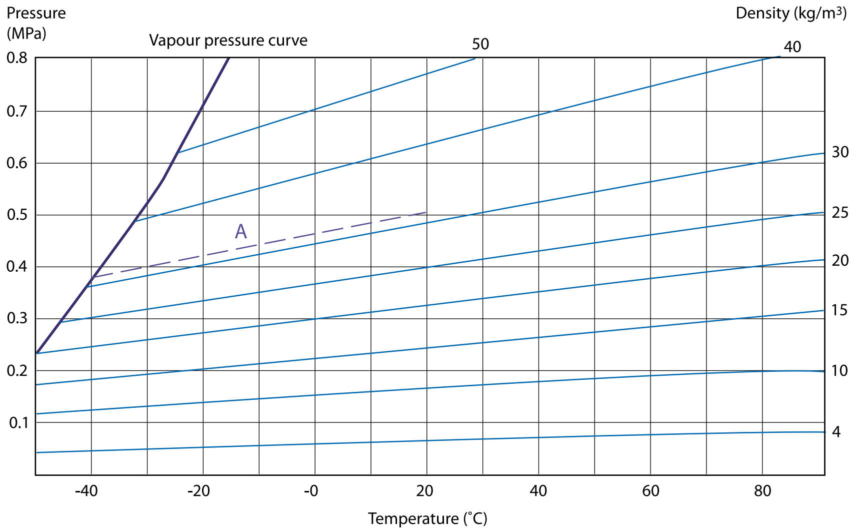


Figure 4.7 Condensation of SF_6 due to temperature and pressure.

In order to avoid gas condensation in circuit breakers operating in cold climates, the gas pressure can be decreased to increase the margin against condensation. However, this may result in derating of the interruption performance.

An alternative solution is to mix the SF_6 with another gas. In the gas mixture, the SF_6 content (partial pressure) gas is kept at a sufficiently low level to avoid condensation at the relevant minimum ambient temperature.
Two normal gas mixtures are:
- SF_6/N_2 (SF_6 and nitrogen)
- SF_6/CF_4 (SF_6 and carbon tetrafluoride)

However, the gas mixture will have less dielectric strength than undiluted SF_6. The interrupting performance is also affected due to the reduced arc cooling efficiency. Derating of the interrupting performance is generally needed when mixed gas is used.

The minimum ambient temperature at which mixed gas is applied, and the corresponding influence on the ratings of the circuit breaker, differs from one type of circuit breaker to another. Table 4.8 shows typical minimum ambient temperature values and the corresponding gas mixtures applied.

Rated pressure	Lowest ambient temperature	Gas composition (%)			Partial pressure (SF_6)
MPa (abs) at 20 °C	°C	SF_6	N_2	CF_4	MPa (abs) at 20 °C
0.5	-40	100			0.5
0.7	-30	100			0.7
0.7	-40	71.4	28.6		0.5
0.7	-40	71.4		28.6	0.5
0.7	-50	51.6	48.4		0.36
0.7	-50	51.6		48.4	0.36
0.8	-25	100			0.8
0.8	-50	44.3		55.7	0.36

Table 4.8 Examples of temperature limits and mixed gas compositions

4.4.2 Moisture content in SF_6 gas

Experience with SF_6 circuit breakers has shown the importance of high levels of dryness to maintain the insulating properties of the gas. All SF_6 circuit breakers are equipped with adsorption agents which will keep the humidity content low.

SF_6 gas is normally delivered with a very low moisture content, but during commissioning and refurbishments the circuit breaker can be subjected to moisture that could be absorbed by the gas. To prevent moisture ingress, the circuit breaker chambers should not be opened in humid environments.

In order to prevent condensation, the maximum allowable moisture content within gas-filled switchgear and control gear filled with gas at the rated filling density shall be such that the dew-point is not higher than -5 °C for measurement at 20 °C (IEC 62271-1).

IEC 60376 specifies the requirements for new SF_6 gas for use in electrical equipment.

4.5 Sound effects of circuit breaker operation

The operation of a circuit breaker will cause sound (or noise in the range between 50 and 1500 Hz) at different levels and intensities depending on the type of circuit breaker and operating mechanism. In urban substations these sound levels can cause problems for the environment, and the sound level of different designs and sound damping walls should be considered.

The typical sound levels produced by different types of circuit breakers at a 10 m distance can be seen below:

Air blast circuit breaker	120 - 130 dB (A)
Oil and SF_6 circuit breakers	95 - 110 dB (A)
SF_6 circuit breakers equipped with motor drive	80 - 90 dB (A)

4.5.1 Standards

International standards regarding the measurement of sound levels and the specification of sound level meters are:

- IEC 61672-1: Sound level meters - Part 1: Specifications
- ANSI S1.13: Measurement of sound pressure levels
- IEEE C37.082: Measurement of sound pressure levels of circuit breakers

IEC does not have a procedure for measurement of sound levels applicable to circuit breakers.

4.5.2 Sound level as function of distance

The sound level is dependent on the distance between the object and the measuring equipment. The sound level decreases approximately as the square of the distance from the sound source. In order to calculate the sound level at a different distance than the one at the time of measurement, the following equation is used:

$$L_x = L_d - 20\log_{10}\left(\frac{x}{d}\right)$$

L_x	Sound level at distance of x m
L_d	Sound level measured at d m

Example:
The sound level of a SF_6 circuit breaker measured at a distance of 10 m has been measured to 102 dB (A). The sound level at 30 m will then be:

$$P_{30} = 102 - 20\log_{10}\left(\frac{30}{10}\right) = 92 \text{ dB (A)}$$

This formula is accurate for distances between 10 m and 300 m from the sound source.

5. Thermal stresses

5.1 Thermal limits

Most of the time during normal operating conditions, the circuit breaker is conducting a certain load current. The IEC and IEEE standards specify maximum temperatures and temperature rises for a circuit breaker when it is carrying its rated continuous current. The major components of a circuit breaker have different temperature limitations. Table 5.1 below shows excerpts from IEC 62271-1.

The upper limit of the normal service temperature according to IEC is +40 °C. At higher ambient temperatures, the permissible temperature rise decreases since the maximum temperature remains unaffected. The method illustrated in Example 2, page 75, can be used for calculations.

	Maximum temperature °C	Maximum temperature rise (Ambient temperature 40 °C.) K
Contacts in SF_6 (silver-plated or bare copper)	105	65
Connections in air (bolted or equivalent) (Bare copper, bare copper alloy, bare aluminum alloy)	90	50
High voltage terminals		
Bare	90	50
Silver or tin-coated	105	65

Table 5.1 Limits of temperature and temperature rise

5.1.1 Derating of rated current due to temperature

In some applications for which customers require higher temperature ratings than the standardized +40 °C, it might be necessary to derate the normal current capability of the circuit breaker. If a customer, for example, requires the maximum ambient temperature of +55 °C, precaution must be taken and the measured temperature rise in the contact system examined, see the following example:

Required maximum temperature	+55 °C
System voltage	145 kV
Rated breaking current	40 kA

As an example the most suitable circuit breaker seems to be a 145 kV breaker with rated current 3,150 A and a measured temperature rise (see Section 5.2) of 53 °C in the main contact system (silver-plated copper). The maximum temperature in the contact system will be:

$$T_{ambient} + T_{measured} = 55 + 53 = 108 \text{ °C}$$

This is higher than the highest allowable value according to IEC (105 °C). As a consequence, the rated service current 3,150 A at 40 °C must be derated one level to 2,500 A to limit the temperature rise in the contact system. If the customer requires the current 3,150 A, a larger circuit breaker must be selected.

5.2 Temperature rise test

In order to verify the current carrying capability of a circuit breaker, a temperature rise test has to be performed. During the test, the temperature of the interrupter parts of the circuit breaker will increase; how much depends on the design of the conductors and contact system. The temperature limits of the different interrupter parts must not be exceeded.

The test is usually performed with the circuit breaker's rated current, and is carried out over a period of time sufficient for the temperature rise to reach a stable value which, according to the standards, is obtained when the increase of the temperature does not exceed 1 K in 1 h. The test procedure is described in IEC 62271-1 and IEEE 37.09.

According to the IEC and IEEE standards, a temperature rise test carried out at 60 Hz is also valid at 50 Hz, and a test performed at 50 Hz is also valid for 60 Hz provided that the temperature rise values recorded during the 50 Hz test do not exceed 95% of maximum permissible values.

Figure 5.1 shows a typical curve of the temperature rise of a circuit breaker T_c versus time. The variation of the ambient temperature T_a is also shown. The change of T_c shall not exceed 1 K/h during the last quarter of the test period. From the curve the thermal time constant can also be determined.

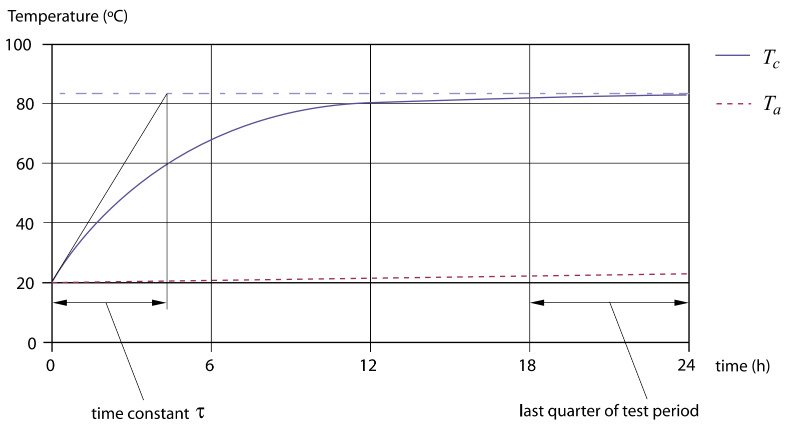


Figure 5.1 Temperature rise in the contact system of a circuit breaker

5.3 Temperature rise at current overload

Circuit breakers may, under certain circumstances, operate at a higher current than the rated current stated by the manufacturer.

The circuit breaker can carry the overload current continuously or for shorter periods of time without exceeding the allowable temperature limitations. However, it should be noted that the overload current must be limited to maximum twice the rated normal current. Otherwise, actual overheating may occur as the heat from hot spots can not be distributed fast enough to colder regions.

In order to determine the circuit breaker's capability to carry overload current, the following parameters are decisive:

- Overload current
- Ambient temperature
- Time duration of overload

The temperature rise at overload is given by the following equation:

$$\Delta T_0 = \Delta T_r \left(\frac{I_0}{I_r}\right)^a$$

Equation 5.1

where

ΔT_o	Temperature rise at overload current (K)
ΔT_r	Temperature rise at rated current (K)
I_o	Overload current (A)
I_r	Rated current (A)
a	Exponent (normally 1.8)

The time-dependent temperature rise (difference between the measured temperature and the ambient) is given by:

$$\Delta T = \Delta T_{\max} \left(1 - e^{-\frac{t}{\tau}}\right)$$

Equation 5.2

where

ΔT	Temperature rise (K)
ΔT_{max}	Maximum temperature rise (K)
t	Time (h)
τ	Thermal time constant (a few hours for circuit breakers)

Combining these two equations gives:

$$\Delta T_0 = \Delta T_r \left(\frac{I_0}{I_r}\right)^a \left(1 - e^{-\frac{t}{\tau}}\right)$$

Equation 5.3

The applications of the equations above are best visualized by some examples:

In addition, larger circuit breaker volumes (for example by choosing larger insulators) will increase the cooling effect and reduce the temperature increase at normal current. Another way to decrease the temperature in the contact system is to use higher pressure of the SF_6 gas in the circuit breaker poles. It may also be necessary to use larger circuit breakers to handle the combination of high normal current and high ambient temperature.

Example 1
A circuit breaker has a maximum temperature rise of 50 K on the silver-plated contacts at steady state conditions with its rated current of 4,000 A. What is the maximum current the circuit breaker can carry continuously?

The maximum permissible temperature rise of a silver-plated contact in SF_6 is 65 K (see Table 5.1). Substituting the values 50 and 65 for ΔT_r and ΔT_0, respectively, in Equation 5.1 gives:

$$50 = 65 \left(\frac{4000}{I_0}\right)^{1.8} \quad \text{or} \quad I_0 = 4000 \left(\frac{65}{50}\right)^{\frac{1}{1.8}} = 4000 \cdot 1.16 = 4628 \text{ A}$$

It should be observed that the temperature rises of other parts of the circuit breaker shall be subjected to the same calculation, and their temperature may not exceed the values specified in the standards.

Example 2
A SF_6 circuit breaker will be installed in a climate in which the maximum ambient temperature is specified as 55 °C. The customer specification states that the rated current of the circuit breaker shall be 2,500 A at that temperature. What will the rated current of the circuit breaker have to be to fulfill this requirement?

Assuming that the circuit breaker will be fitted with silver-plated contacts, the maximum allowable temperature rise of such contacts in SF_6 is 65 K, in accordance with the standards. This means that the maximum allowable total temperature of the silver-plated contacts is 105 °C (= temperature rise plus standard maximum ambient of 40 °C). The customer specification states that the maximum ambient temperature is 55 °C, which means that the maximum temperature rise of the silver-plated contact will be limited to 105 - 55 = 50 K at 2,500 A.

Substituting 65 K for ΔT_0, and 50 K for ΔT_r in Equation 5.1 will give:

$$65 = 50\,(\frac{I_0}{2500})^{1.8} \quad \text{or} \quad (\frac{65}{50})^{\frac{1}{1.8}} = \frac{I_0}{2500} \Rightarrow I_0 = 2892\ \text{A}$$

The current rating closest to the current of 2,892 A is 3,150 A, in accordance with IEC 62271-1, and 3,000 A in accordance with IEEE C37.06.

Example 3:
A SF_6 circuit breaker with a rated current of 2,500 A is normally run at 2,000 A, except during a certain period of the day, when the current is increased to 3,000 A. How long can this circuit breaker be run at this elevated current without overheating, assuming the ambient temperature is 40 °C ?

Assuming that the circuit breaker reaches a maximum temperature rise at 2,500 A of 65 K (silver-plated contacts), the maximum temperature rise at 2,000 A can be found using Equation 5.1.

$$65 = \Delta T_r\,(\frac{2500}{2000})^{1.8} \Rightarrow \Delta T_r = 65\,(\frac{2000}{2500})^{1.8} = 43.5\ \text{K}$$

Inserting this value in Equation 5.3, we get:

$$65 = 43.5\,(\frac{3000}{2000})^{1.8}\,(1 - e^{-\frac{t}{1.5}}), \quad \text{or} \quad 1 - e^{-\frac{t}{1.5}} = 0.72 \Rightarrow t = 1.9\ \text{h}$$

This means that the circuit breaker can be run at 3,000 A for a period of 1 hour and 54 minutes before the temperature rise of the contacts will exceed 65 K.

When doing calculations as above, the uncertainties of the calculations must be taken into consideration; use margins at the calculated results to ensure proper functioning of the system.

5.4 Influence of site altitude

The measured temperature rise from a test at altitudes below 2,000 m should be reconsidered, according to IEC, for a circuit breaker located at an altitude between 2,000 and 4,000 meters. The measured temperature at normal conditions shall not exceed the limits given in Table 3 of IEC 662271-1, reduced by 1% for every 100 m in excess of 2,000 m.

This compensation is generally unnecessary; the higher temperature rise at higher altitudes due to the reduced cooling effect of the air is compensated by reduced maximum ambient temperature at the altitude (see Table 5.2). Consequently, the final temperature is relatively unchanged at a given current.

Altitude m	Maximum ambient air temperature ºC
0 - 2000	40
2000 - 3000	30
3000 - 4000	25

Table 5.2 Maximum ambient temperature versus altitude

6. Insulation requirements

This chapter presents the requirements on the circuit breaker to operate at its rated voltage and within its ratings of insulation data. Other factors which have influence on the insulation, such as ambient conditions, creepage distance and flash-over distance, are mentioned.

6.1 Insulation co-ordination

IEC defines insulation co-ordination as “the selection of the dielectric strength of equipment in relation to the voltages which can appear on the system for which the equipment is intended and taking into account the characteristics of the available protective devices.”) This means that circuit breakers and other electrical equipment must withstand the operational system voltage as well as the overvoltages occurring in the network. Therefore certain insulation requirements are specified for each level of system voltage. Voltage withstand requirements given in today’s standards are based on experience, calculations and statistics. The withstand capability has to be verified by type tests and routine tests in accordance with the relevant standards.

The overvoltages can be atmospheric discharges (lightning) and switching surges, or they can be temporary overvoltages at power frequency.

6.2 Overvoltages

6.2.1 Short-duration power frequency voltage

Under certain conditions, temporary overvoltages may occur in a power system. A typical reason is single-phase earth faults, which will lead to increased power frequency voltage on the healthy phases.
The standard voltage for the temporary over-voltage is the short-duration power-frequency voltage, a normal alternating voltage with a frequency in the range of 48 to 62 Hz. It is normally referred to as the power-frequency voltage.

6.2.2 Lightning impulse

Lightning strokes, e.g. to an overhead line, will lead to overvoltages in the power system. The highest amplitudes that can occur depend on the dielectric withstand capability of the insulation and of the surge arresters in the system. Therefore there is a relationship between the rated voltage of the system and the lightning impulse amplitude specified by the standards.

The shape of the lightning impulse (often referred to as short wave) is defined by the amplitude, the front time and the time to half-value (see Figure 6.1).

The front time (T_1) is defined as 1.67 times the interval T between the instants when the impulse is 30% and 90% of the peak value (points A and B).

The time to half-value is defined as the time interval between the virtual origin O_1 (the point where the straight line through A and B intersects the time axis) and the instant on the tail when the voltage has decreased to 50% of the peak value.

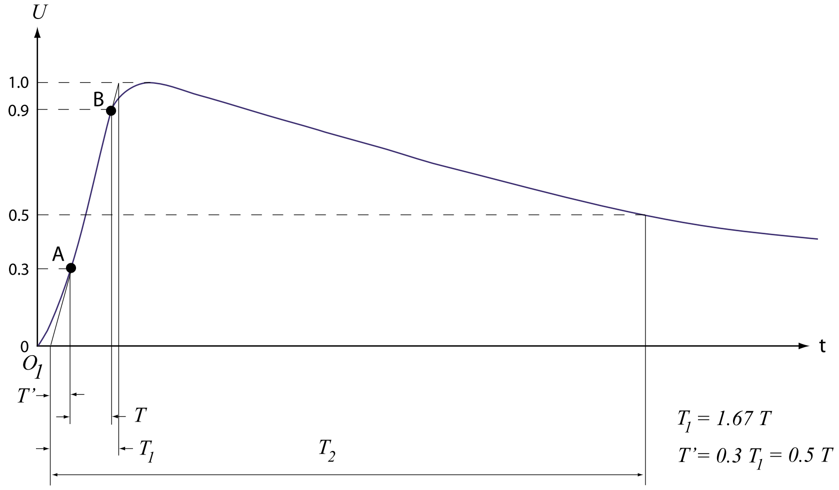


Figure 6.1 (Full) Lightning impulse

T_1	Front time (1.2 μs ± 30%)
O_1	Virtual origin
T_2	Time to half-value (50 μs ± 20%)

Tolerance of the peak value: ± 3%

The amplitude value of the lightning impulse is known as the Lightning Impulse Withstand Level (LIWL). The older expression BIL (Basic Insulation Level) means the same as LIWL.

6.2.3 Chopped impulse

The chopped lightning impulse is also referred to as chopped wave, and is specified in the IEEE standards. It simulates the condition when a lightning overvoltage leads to a flashover, e.g. across a line insulator in the system.

In a test circuit the rapid collapse of the voltage will usually be achieved by means of a triggered spark gap. The voltage drops to zero or close to zero, with or without oscillations (see Figure 6.2). The amplitude of the chopped lightning impulses specified for type tests is higher than for the corresponding full impulses.

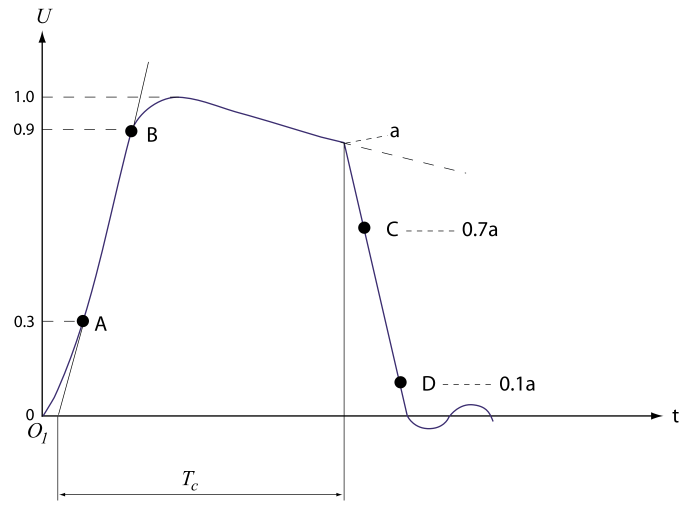


Figure 6.2 Chopped wave

T_c	Time to chopping
C and D	Define the duration of voltage collapse (1.67 times the time interval between C and D) and are used for definition purposes only

The time to chopping (T_c) is the time interval between the virtual origin O_1 and the instant of chopping. IEEE specifies two values for T_c; 2 μs and 3 μs respectively.

6.2.4 Switching impulse

The standard wave shape of the switching impulse is a slow-front over-voltage which simulates the transient voltage created at switching of (other) circuit breakers. The time to peak T_p is 250 μs with a time to half-value of 2,500 μs (see Figure 6.3).
The term SIWL (Switching Impulse Withstand Level) is used to characterize the withstand level of equipment in terms of switching impulse.

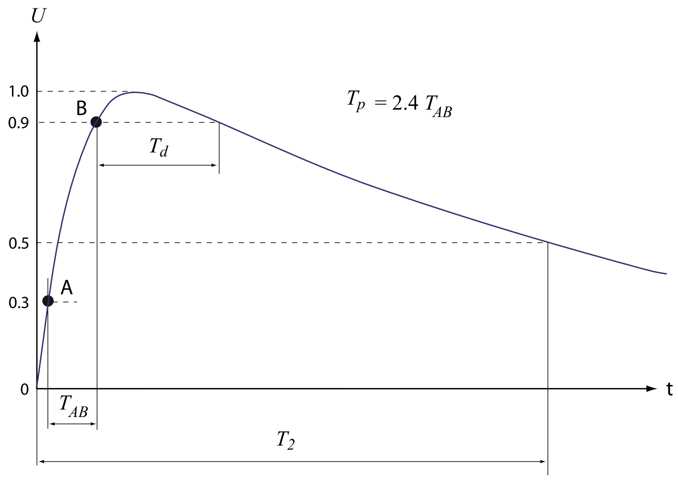


Figure 6.3 Full switching impulse

T_d	Time above 90% of peak value
T_2	Time to half value, (2,500 μs ± 60%)
T_{AB}	Time from 30% to 90% of the peak value
T_p	Time to peak. 2.4 times the interval when the voltage is 30% to 90% of the peak value, (tolerance ± 20%)

Tolerance of the peak value ± 3%

6.3 Insulation levels

For low- and moderate-rated voltages, the lightning overvoltages give more severe stress on the insulation than the switching overvoltages do. At high-rated voltages the situation will change, and the switching overvoltages give more severe stress. IEC therefore uses two different principles for their requirements, depending on the rated voltage. A split into two ranges of rated voltage has been made as follows (IEC 62271-1):

Range I	Range II
1 kV ≤ U_r ≤ 245 kV	U_r > 245 kV

where U_r is the rated voltage.

In the IEEE standards for circuit breakers (C37.04, C37.06 and C37.09), there is no such split in different voltage levels.

Table 6.1 comprises values in accordance with IEC 62271-1 and IEEE C37.06 for the withstand voltages to ground, between phases and between the open contacts. For IEEE and IEC range I, the voltage values between open contacts and to ground are identical. For IEC range II the values are different. As can be seen, IEC specifies SIWL only for rated voltage 300 kV (for IEEE 362 kV) and above.

6. Insulation requirements

IEC 52 - 245 kV

Rated voltage U_r kV	Power frequency dry/wet kV rms	Lightning impulse withstand level (LIWL) 1.2 x 50 µs kV peak
52	95	250
72.5	140	325
123	185/230	450/550
145	230/275	550/650
170	275/325	650/750
245	360/395/460	850/950/1050

IEC 300 - 800 kV

Rated voltage U_r	Power frequency		Lightning impulse withstand level (LIWL) 1.2 x 50 µs		Switching impulse withstand level (SIWL) 250 x 2500 µs	
	To ground, dry	Across pole, dry	To ground	Across pole*	To ground/ between phases	Across pole*
kV	kV rms	kV rms	kV peak	kV peak	kV peak	kV peak
300	380	435	950	950 (170)	750/1125	850
			1050	1050 (170)	850/1275	700 (245)
362	450	520	1050	1050 (205)	850/1275	950
			1175	1175 (205)	950/1425	800 (295)
420	520	610	1300	1300 (240)	950/1425	1050
			1425	1425 (240)	1050/1575	900 (345)
550	620	800	1425	1425 (315)	1050/1680	1175
			1550	1550 (315)	1175/1760	900 (450)
800	830	1150	2100	2100 (455)	1425/2420	1175 (650)
					1550/2480	

*) The values in brackets refer to the peak of the power frequency voltage (bias voltage) that has to be applied to the opposite terminal when a combined voltage test is required, see Figure 6.4.
Note: For disconnectors, the withstand voltage requirements across open pole are more severe than those for circuit breakers. These higher withstand requirements shall also be fulfilled by disconnecting circuit breakers.

Table 6.1a Withstand voltages to ground and across open contacts

For most of the rated voltages, IEC states several rated insulation levels to allow for application of different performance criteria or overvoltage patterns. The choice should be made considering the degree of exposure to fast-front and slow-front overvoltages, the type of neutral earthing of the system and the type of overvoltage limiting devices (see IEC 60071-2).

Circuit breakers are normally type tested with the highest insulation value for each voltage level.

IEEE

Rated voltage U_r	Power frequency dry/wet		Lightning impulse withstand level (LIWL) 1.2 x 50 µs	Chopped wave		Switching impulse withstand level (SIWL) 250 x 2500 µs	
	Dry	10 s, wet		2 µs	3 µs	To ground/ between phases	Across pole
kV	kV rms	kV rms	kV peak	kV peak	kV peak	kV peak	kV peak
72.5	160	140	350	452	402		
123	260	230	550	710	632		
145	310	275	650	838	748		
170	365	315	750	968	862		
245	425	350	900	1160	1040		
362	555	-	1300	1680	1500	825	900
550	860	-	1800	2320	2070	1175	1300
800	960	-	2050	2640	2360	1425	1550

Table 6.1b Withstand voltages to ground and across open contacts

6.4 Dielectric tests on circuit breakers

6.4.1 General

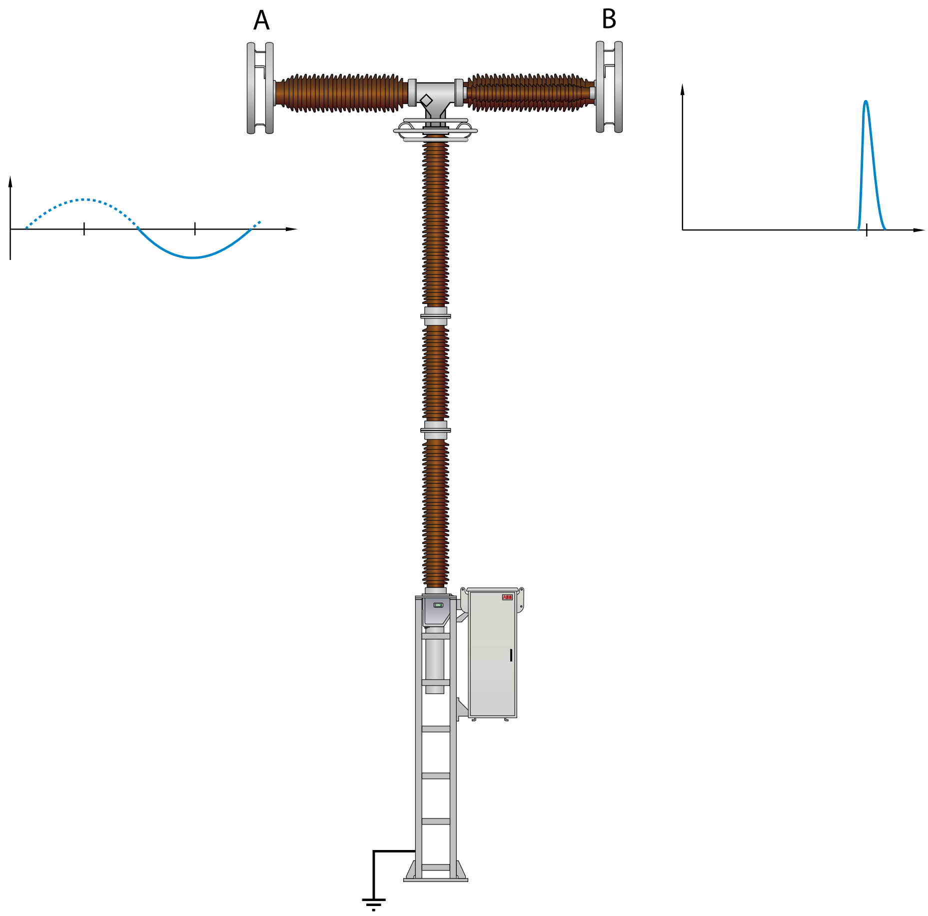
In order to prove that a circuit breaker complies with the required insulation levels indicated in Table 6.1, it must be submitted to type tests. The wave shapes are shown in Figure 6.2. As can be seen from Table 6.1, the required values such as amplitude and type of impulse voltages can differ from one standard to another. The test procedures can also be different. Reference is made to IEC 62271-1 and IEEE Standard 4, respectively, where the test procedures are described.
In some cases, the voltage withstand capability of circuit breakers is improved by means of grading/corona rings. Such rings will also help to achieve low RIV (radio interference voltage) levels.

6.4.2 Combined voltage test

In a combined voltage test, or bias test, the circuit breaker is submitted to two separate voltages at the same time: at one terminal, a power frequency voltage and at the other terminal, either a switching or lightning impulse. See Figure 6.4. The test simulates the actual voltage conditions that an open circuit breaker may experience. The peak of the impulse wave coincides with the opposite peak of the power frequency voltage, and the total voltage between the terminals will be the sum of the two voltages.

For switching impulse bias tests, the power frequency voltage on the opposite terminal corresponds to the rated (phase-to-ground) voltage of the system. This reflects real conditions, since switching overvoltages often occur around the peak of the power frequency voltage wave. For lightning impulse bias tests, on the other hand, the power frequency voltage corresponds to 70% of the rated (phase-to-ground) voltage. The reason is that lightning overvoltages occur quite randomly in time, and the standards have settled for a compromise between the least and the most severe stresses.

For simplicity of testing, it is permissible to replace the bias test with a test in which switching or lightning impulses are applied to one terminal of the circuit breaker, with the other terminal earthed. In this case the amplitude of the impulses shall be equal to the sum of the impulses and the peak of the power frequency voltage as used in the bias test. Due to more uneven voltage distribution, however, this test is more severe than the bias test. Therefore the test is to be used only if the circuit breaker to be tested is deemed to have sufficient margins in dielectric withstand strength.



A	Power frequency voltage applied on terminal A.
B	Switching or lightning impulse voltage applied on terminal B. Synchronized with the maximum value of the negative power frequency voltage.

Figure 6.4 Combined voltage test on a two-element circuit breaker with grading/corona rings.

6.4.3 Other voltage tests

In addition to the circuit breaker's withstand capability against power frequency voltage, lightning impulse and switching impulse, there are several other cases of over-voltages which the circuit breaker must resist.

6.4.3.1 RIV (Radio Interference Voltage) tests

As with all other types of HV equipment, an energized circuit breaker may generate radio interference voltages, RIV. These are high-frequency disturbances, typically caused by electrical discharges (corona) from sharp edges of terminals, etc.

IEC 62271-100 specifies that RIV tests are applicable to circuit breakers having a rated voltage of 123 kV and above. The required test procedure is in accordance with CISPR Publication 16 and is described in detail in IEC 62271-1. The RIV level shall not exceed 2,500 µV at a test voltage 10% above the rated phase-to-ground voltage. The test voltage is applied for 5 minutes and the measurement is performed at a frequency of 500 - 2,000 kHz.

The corresponding values according to IEEE C37.09 are given in NEMA Publication 107. The test voltage is 1.05 times the rated phase-to-ground voltage. The allowable values of the interference level are given in NEMA Standards Publication SG 4, Table 4-1. The highest allowable interference level from 123 kV and upwards is 2,500 µV at 1,000 kHz.

6.4.3.2 Partial discharge test

A partial discharge tests will reveal the same kind of disturbances as an RIV test, but is mainly used for detection of weaknesses in the internal insulation of components such as bushings and grading capacitors.
This test is normally not required for live tank circuit breakers. IEC 62271-100 states that the test should be performed only if the circuit breaker uses components for which a relevant standard exists (for example bushings). For the sake of interest, it is worth noting that the test is carried out with a test voltage 10% above the rated phase-ground voltage. The partial discharge should not exceed 5 pC.

6.4.3.3 Pollution test

The intention with this artificial test is to simulate the operating conditions at a certain degree of pollution (see Section 6.7.1). However, in most cases this test is not required. If the creepage distance complies with the requirement mentioned in Table 6.3, the artificial pollution test is not necessary (see IEC 60507).

The test procedure and requirements are described in IEC 60060-1 and IEC 60507 respectively. In short, the circuit breaker covered by a layer of salt solution corresponding to the specified contamination is submitted to a test voltage equal to its rated phase-to-ground voltage.

6.4.3.4 Tests on low-voltage circuits

Even the low-voltage circuits (control, motor, heater, etc.) must be submitted to voltage tests. The requirement according to IEC 62271-1 is:

– Power frequency voltage: 2 kV rms 1 min.

6.5 Atmospheric correction factor

The withstand capability of external insulation is affected by the atmospheric pressure, temperature and humidity. The withstand values given in Table 6.1 are valid for standard atmospheric conditions, which are defined as:

- temperature t_0 = 20 °C
- pressure b_0 = 101,3 kPa (older expression 1013 mbar)
- humidity h_0 = 11 g/m^3

If the atmospheric conditions at the testing site deviate from the standard, correction factors may be applied for air density and humidity. The voltage applied during a test on external insulation is then determined by multiplying the specified test voltage by the atmospheric correction factor, which is defined in IEC 60060-1:
$K_t = k_1\, k_2$ where

$$k_1 = \left(\frac{b}{b_0}\right)^m \left(\frac{273 + t_0}{273 + t}\right)^m$$

k_1	air density correction factor
b	atmospheric pressure at test occasion
t	temperature at test occasion
m	exponent defined in IEC 60060-1

$$k_2 = k^w$$

k_2	humidity correction factor
k	factor depending on the type of test voltage
w	exponent defined in IEC 60060-1

A test report on dielectric tests normally states absolute voltages in accordance with the standard requirements. To obtain the actual stresses on the circuit breakers, external insulation should be applied during the test correction. The maximum allowable correction factor for any test is 5%; the values given in the report may be divided by max 1.05 or 0.95 (whichever is applicable) in order to obtain the correct impulse level.

Example:
For a test on a 245 kV circuit breaker, the test voltage used at the test was 1050 kV. The correction factor K_t during the test was 0.95 or lower, but was not applied. This means that the external insulation was stressed at a voltage of at least 1050/0.95 = 1105 kV. This knowledge can sometimes be used for installations at high altitude, or when a customer requires insulation levels slightly higher than the standardized values. RIV tests and low-voltage tests are not affected by the atmospheric correction factor.

6.6 Installation at high altitudes

Both IEC 62271-100 and ANSI/IEEE C37.04 state that the rated insulation levels are valid for installations at an altitude of maximum 1000 m above sea level.

For this reason, one must be careful when equipment is intended for installation at altitudes higher than 1000 m. In this case, the insulation level of external insulation related to the standard atmospheric conditions can be determined by multiplying the rated insulation level at the service location with a constant K_a, given by the following formula (see also IEC 62271-1 and ANSI/IEEE C37.010):

$$K_a = e^{m \frac{H-1000}{8150}}$$

where H is the service altitude in meters and m is a factor depending on wave shape

$m = 1$	for power frequency, lightning impulse and phase-to-phase switching impulse voltages
$m = 0.9$	for longitudinal (across open circuit breaker) switching impulse voltage
$m = 0.75$	for phase-to-earth switching impulse voltage

The correlation can be seen graphically in Figure 6.5.

For internal insulation, the dielectric characteristics are identical at any altitude and no special precautions need to be taken.

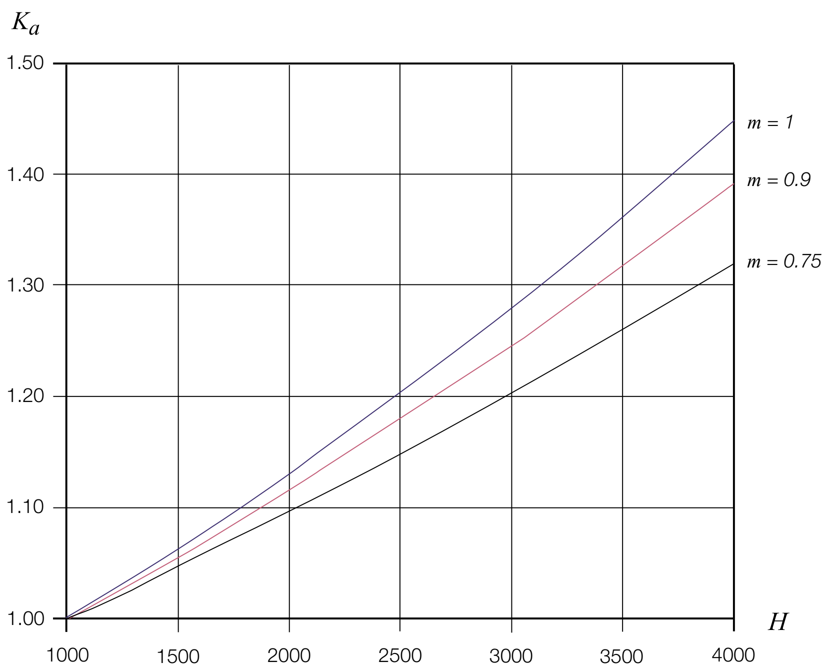


Figure 6.5 Altitude correction factor

Example:
A 170 kV circuit breaker is going to be installed at an altitude of 2,200 m above sea level. The customer specification calls for an insulation level of 750 kV at site level.

Which circuit breaker will fulfill the requirements?

The required insulation level at sea level will be obtained using the formula for K_a given above, and the following considerations:
- For lightning impulse and power frequency $m = 1$, hence $K_a = 1.16$.
  This means that the circuit breaker needs to be tested at sea level with a voltage of $750 \cdot K_a = 870$ kV.
- The nearest standardized impulse voltage is 1050 kV, which belongs to a system voltage of 245 kV.
- The requirement for the power frequency withstand at sea level is 377 kV (325 · 1.16) (dry and wet). This is covered by the requirements, (460 kV) for a 245 kV circuit breaker.

Conclusion: The circuit breaker fulfilling the requirements for the high altitude will be a breaker with insulation levels belonging to a system voltage of 245 kV.

6.7 Environmental effects and insulator shapes

6.7.1 Creepage distance and pollution
Depending on the site conditions, insulator surfaces of outdoor equipment will sooner or later collect deposits. When the deposits mainly consist of salt, which is normal in coastal regions, the surface resistance of the insulator decreases. The insulation withstand capability of the insulator is therefore essentially reduced, especially in periods of dew or fog. Heating due to the leakage current resulting in uneven drying of the surface can cause partial discharges (streamers), which might lead to a disruptive discharge across the insulator (flashover).

During periods of rain, the insulators are naturally washed. Substations in, for example, coastal areas often have routines established to prevent the build up of heavy deposits of salt on the insulators. These routines range from manual cleaning to fully automatic cleaning.

In areas with heavy pollution, composite insulators with silicone sheds can be used to minimize or even eliminate the need for cleaning. Due to the chemical nature of silicone rubber, the insulator surface is hydrophobic (non-wetting). Water on the surface stays as droplets and does not form a continuous water film. This means that any leakage current along the insulator surface is strongly suppressed.

6.7.2 Environmental classes according to IEC

The creepage distance is dependent on the degree of pollution. The original four pollution levels characterizing the site severity have, in the latest edition of IEC 60815, been replaced with five new levels that do not correspond directly to the previous number classes:

a	Very light
b	Light
c	Medium
d	Heavy
e	Very heavy

NOTE! In the latest edition of IEC 60815, the creepage distance is specified as Unified Specific Creepage Distance, (USCD). The definition is the creepage distance of an insulator divided by the maximum operating voltage across the insulator, for AC systems $U_m/\sqrt{3}$. It is generally expressed in mm/kV.

This definition differs from that of Specific Creepage Distance, where phase-to-phase value of the highest voltage for the equipment is used. For phase-to-earth insulation, this definition will result in a value that is √3 times that given by the definition of Specific Creepage Distance in IEC 60815 (1986). Table 6.2 shows the Unified Specific Creepage Distance in relation to the specific creepage distance.

Pollution level	Unified Specific Creepage Distance (phase-ground voltage) mm/kV	Specific Creepage Distance (phase-phase voltage) mm/kV
a - Very light	22	-
b - Light	28	(16)
c - Medium	35	(20)
d - Heavy	44	(25)
e - Very heavy	55	(31)

Table 6.2 USCD in relation to Specific Creepage Distance.

To choose the correct creepage distance, the information gathered regarding the pollution at the site, Site Pollution Severity (SPS) class, can be used. Three different approaches for insulator selection are given in IEC 60815-1:
– Approach 1: Use past experience. Past experience from field or test station at the same site, nearby site or a site with similar conditions.
– Approach 2: Measure and test. Measure or estimate the pollution level at site, select appropriate candidate insulators, check for performed test results or complete with needed tests, if necessary adjust selection/size according to test results.
– Approach 3: Measure and design. Measure or estimate the pollution level at site, use guidance from IEC 60815-1 to get input to design an appropriate insulator.

In nature, the change from one class to another is gradual; hence if measurements are available, the actual Site Pollution Severity (SPS) value, rather than the class, can be taken into account when determining insulator dimensions. Figure 6.6 shows the SPS classes and curve in relation to the Unified Specific Creepage Distance.

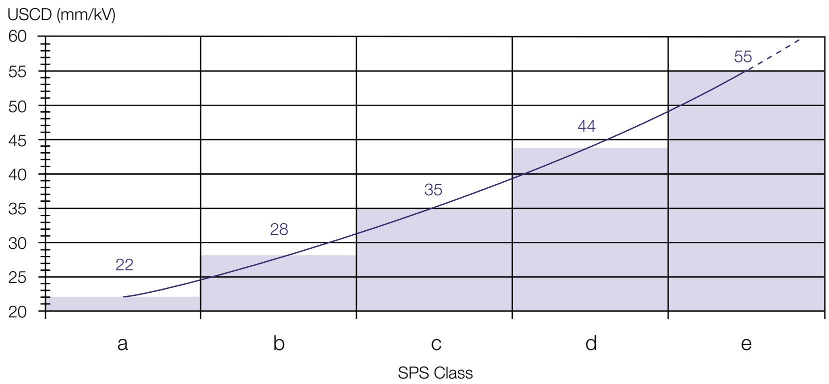


Figure 6.6 The SPS classes and curve in relation to the Unified Specific Creepage Distance.

6.7.3 Environmental classes according to IEEE

The IEEE requirements regarding creepage distances are stated in IEEE C37.010. The requirements are basically the same as for IEC, with the exception that four classes still are used. The values are given in Table 6.3.

Pollution level	Minimum nominal specific creepage distance mm/kV (line-to-ground voltage)
Light	28
Medium	35
Heavy	44
Very heavy	54

Table 6.3 Creepage distance according to IEEE

6.8 Clearances in air

IEC 60071-2 states values for the phase-to-earth and phase-to-phase air clearances. Table 6.4 shows the correlation between standard lightning impulse withstand voltages phase-to-ground and phase-to-phase, and minimum air clearances.

Standard lightning impulse withstand voltage kV	Minimum clearance in air mm
325	630
450	900
550	1100
650	1300
750	1500
850	1700
950	1900
1050	2100
1175	2350
1300	2600
1425	2850
1550	3100
1675	3350
1800	3600
1950	3900
2100	4200

Table 6.4
Correlation between standard lightning impulse withstand voltages phase-to-earth and phase-to-phase and minimum air clearances

Corresponding correlation tables for switching impulse and minimum clearance are given in IEC 60071-2.

It should be noted, however, that IEC 60071-2, Appendix A states that these clearances may be lower if it has been proven by tests on actual or similar configurations that the standard impulse withstand voltages are met, taking into account all relevant environmental conditions which can create irregularities on the surface of the electrodes, for example rain or pollution. The distances are therefore not applicable to equipment that has an impulse type test included in the specification, since mandatory clearance might hamper the design of equipment, increase its cost and impede progress.

6.9 Insulating material

Porcelain is the traditional material for outdoor insulation, but in recent years several types of composite material have become more and more common.

ABB can now deliver composite insulators with silicone rubber (SIR) sheds for all high-voltage equipment. (See our Buyer's Guide for Live Tank Circuit Breakers, chapter on Composite Insulators).

Several field tests indicate that pollution performance and the short-term and long-term hydrophobicity characteristics of composite insulators with silicone rubber are better than those of porcelain insulators.

Considering both aging and pollution performance, in most cases it is possible to reduce creepage distance in coastal areas by a minimum one pollution level according to ABB experiences when composite insulators are used.

7. Application

7.1 Transmission line circuit breakers

Approximately 50% of all circuit breakers installed are used for transmission line application, i.e. they are directly connected to a transmission line. Transmission line circuit breakers normally switch currents associated with the following switching cases:
- Terminal faults (see 3.2)
- Short-line faults (see 3.3)
- Out-of-phase faults (see 3.5)
- No-load transmission line (see 3.6)

Normally rapid auto-reclosing is specified for line circuit breakers.
The operating duty cycle in accordance with IEC 62271-100 is:

O - 0.3 s - CO - 3 min - CO

Normally the time 3 minutes between the two close-open operations is valid, but as an alternative IEC specifies that the time values 15 s or 1 min can also be used. The dead time of 0.3 s is based on the recovery time of the air surrounding an external arc in the system (i.e. a short-circuit). The time of 3 min is the time needed for the operating mechanism to restore its power after a O - 0.3 s - CO. Modern spring and hydraulic operating mechanisms do not need 3 min to restore their power. However, shortening of the restore time and expanding the duty cycle beyond the standard duty cycle should be approached with caution.

7.1.1 Faults on overhead lines

Faults can appear anywhere in the network, at any given time. They can be single-phase, two-phase or three-phase. In almost all cases faults include earth. That fact is also the basis of the rating used in IEC 62271-100.

Most faults occur on transmission lines, which means that transmission line circuit breakers are exposed to wear caused by short-circuits. However, the average frequency of occurrence of short-circuits is low, and the magnitude is normally below 60% of the capability of the circuit breaker. Extended electrical endurance is not required for transmission line circuit breakers.

There can be several causes for faults on a transmission line:

a. Lightning: One of the most common causes. A lightning flash can hit the tower and cause a backflash across one of the string insulators. Another cause can be a direct flash on one of the phase conductors. This may happen when the transmission line is not protected by shield wire or after a shield wire failure.

   One particular aspect of lightning is the occurrence of multiple stroke lightning flashes. Although their occurrence has a low probability, they need to be considered. When a circuit breaker is in the process of interrupting a short-circuit that is the result of a lightning flash and there is a second or third stroke, the opening contact gap is exposed to a voltage wave with a steep front. This voltage may exceed the dielectric withstand of the contact gap and a flashover may occur

across the contact gap. If multiple stroke lightning flashes are expected, the circuit breaker should be protected by means of surge arresters, located on the line side of the circuit breaker. Such surge arresters will also protect other HV equipment on the line side, such as voltage transformers.

b. Wind: During periods of strong winds in combination with an unfavorable direction, galloping of lines my occur. Under those conditions two phase conductors may touch, causing a two-phase fault.

c. Nature: Trees may fall on a line or sagging of the phase conductors, causing flashovers to trees located under the mid span during extremely warm weather.

d. Bushfires: Bushfires may be caused by lightning or human intervention. When a firestorm passes under a transmission line, the hot air may cause phase-to-phase or phase-to-ground flashovers.

7.1.2 Switching of no-load transmission lines

7.1.2.1 Voltage factor

The switching of no-load transmission lines is treated in Section 3.6. Section 3.6 also contains information regarding the capacitive voltage factor k_c to be used when performing single-phase tests as a substitute for three-phase tests. The following applies for transmission lines during normal service conditions (i.e. without faults present):

k_c = 1.2 for transmission lines in effectively earthed systems
k_c = 1.4 for transmission line in non-effectively earthed systems

In effectively earthed systems in the presence of single or two-phase earth faults:

k_c = 1.4 applies

There are special cases, for example with multiple overhead line constructions having parallel circuits, where due to the capacitive coupling between the systems, a voltage factor of 1.2 is not sufficient. For such systems a voltage factor of 1.3 is considered sufficient.

7.1.2.2 Line charging current

The preferred values of line charging current given in IEC 62271-100 are covering applications where the line length does not exceed 400 km at 362 kV to 550 kV. For longer lines, the current is higher. This does not pose a problem for modern SF_6 circuit breakers.

7.1.2.3 Reclosing

In the case of a fault on the transmission line, the circuit breakers at both ends of the line are opened and one of the two circuit breakers interrupts the fault. Provided that the circuit breakers are single-pole operated, the protection system may be arranged to open only the faulted phase(s), and leave the healthy phase(s) unaffected. As a result, the line will still have some transmission capability left. This will help to maintain stability in large, heavily loaded transmission systems. If all three poles of the circuit breaker are opened, the poles not interrupting the fault are switching a no-load transmission line. When the circuit breaker recloses, the poles switching the no-load transmission line are now energizing the transmission line. As a worst case, this energizing may occur when the trapped charge on the line is at opposite polarity. The poles energizing the faulted line are energizing a transmission line without trapped charge. One way of limiting the voltage transients associated with the energizing of no-load transmission lines is by using preinsertion resistors. The value of the resistance is in the order of the surge impedance of the line (a typical resistance value is 400 Ω) and the preinsertion time 8 – 12 ms to guarantee that the voltage wave has traveled out and back a couple of times before the main contacts close.

Another way of limiting the voltage transients is using controlled switching. This is described in ABB Controlled Switching, Buyer's and Application Guide.

7.1.2.4 Shunt compensated transmission lines

Long transmission lines may be equipped with shunt compensation (directly connected shunt reactors) that is used to compensate the reactive power generation in times when the transmission line is lightly loaded. The presence of shunt reactors will result in less severe interrupting conditions for the circuit breaker when switching the no-load transmission line current. This is due to the fact that the load side of the circuit breaker no longer sees a dc voltage due to trapped charge, but a rather low frequency ac voltage, the frequency depending on the degree of compensation.

7.1.2.5 Series compensated transmission lines

To increase the transmitted power of long transmission lines, series compensation (series capacitor) may be used. The presence of series capacitors may increase the severity of the TRV imposed on the line circuit breakers during fault interruption. Under special fault conditions, delayed current zeros may occur and the circuit breaker may need to be adapted for this special duty.

7.1.3 Classification

The normal operating frequency of transmission line circuit breakers is low, perhaps a few times per year. That means that a class M1 circuit breaker is sufficient. Only in rare cases where frequent switching of transmission lines is anticipated is a class M2 circuit breaker recommended.

As the number of faults per km transmission line per year is low, and taking into account the fact that the magnitude of most fault currents is lower than 60% of the capability of the circuit breaker, a class E1 circuit breaker is sufficient. Only in rare cases where frequent switching of high fault current is anticipated is a class E2 circuit breaker recommended.

For infrequently-operated transmission line circuit breakers, class C1 is sufficient. Class C2 is recommended for frequently-switched transmission line circuit breakers.

7.2 Power transformer circuit breakers

Approximately 25% of all circuit breakers installed are used for power transformers, making it the second-most common application after transmission lines. Normally, transformer circuit breakers are switched infrequently, in many cases only a few times per year. There are, however, exceptions where high switching frequencies may be encountered, e.g. power transformers associated with peak power installations (such as pumped storage plants) or arc furnaces.

Three-pole operated circuit breakers are normally used, as single-phase interruption of transformer faults is not applied. One reason, however, for use of single-pole operated circuit breakers may be to optimize controlled switching conditions, in order to minimize inrush currents.

If a short-circuit occurs in a power transformer (or adjacent parts of the substation) the transformer circuit breaker will open and interrupt the fault current. In contrast to line circuit breakers, no reclosing operations will be made.

An extreme case may occur for circuit breakers close to centers of generation, typically placed on the high-voltage side of large generator step-up (GSU) transformers. In this location the ac component of the short-circuit current may decrease more quickly than in the normal case. The short-circuit current may then not have a current zero for a number of cycles, preventing interruption of the current. In such circumstances the duty of the circuit breaker can be eased, for example, by delaying its opening. Alternatively, it may be proven by tests or calculations that the arc voltage of the circuit breaker is high enough to damp the dc component of the current so much that a current zero will occur.

7.2.1 Asymmetry and dc time constant

Power transformers generally have higher X/R ratios than lines and cables. Therefore, in situations where the impedances of power transformers have a dominating influence on the short circuit current level, the dc time constant may be higher than the standard value 45 ms. A typical case is a busbar of a substation with power infeed solely through power transformers. In most cases, however, this situation is also associated with short-circuit current levels far below the rated short-circuit current of the associated circuit breakers. Therefore, the stresses will still be adequately covered by circuit breakers with standard time constant 45 ms. An exception to this general situation may occur in medium-voltage networks (≤52 kV), where the infeed through power transformers may approach the rated short circuit current of the circuit breakers. For this situation an alternative time constant 120 ms is specified in the IEC standards.

An extreme case may occur for circuit breakers close to centers of generation, typically placed on the high-voltage side of large generator step-up (GSU) transformers. In this location the ac component of the short-circuit current may decrease more quickly than in the normal case. The short-circuit current may then not have a current zero for a number of cycles, preventing interruption of the current. In such circumstances the duty of the circuit breaker can be eased, for example, by delaying its opening. Alternatively, it may be proven by tests or calculations that the arc voltage of the circuit breaker is high enough to damp the dc component of the current so much that a current zero will occur.

7.2.2 No-load switching conditions

When a power transformer is energized by closing of the circuit breaker, quite severe inrush currents may occur. The magnitude will depend on the point-on-wave energizing instant and on the amount of residual flux in the transformer core. It is often important to limit the inrush current magnitude, and one efficient method to do that is by controlled switching of the circuit breaker. Refer to ABB Controlled Switching, Buyer's and Application Guide for further information on this subject.

Interruption of the no-load current of a power transformer is a case of interruption of low inductive currents. Due to the strong damping of the voltage transients resulting from interruption, this is generally regarded as an easy switching case. See also Section 3.7.2.

7.2.3 Synchronization

In power stations, the generator-transformer blocks will normally be synchronized and connected to the network by means of the circuit breakers on the high-voltage side of the GSU power transformers. During synchronization, these circuit breakers will for some time be subjected to relatively high ac voltage across the open poles. In general, these voltage stresses are adequately covered by the normal ac voltage type tests, but extra-long creepage distances may be specified for the insulation across open poles, especially if severe climatic conditions are expected.

For these circuit breakers, there is also the risk that they will have to interrupt under out-of-phase conditions, following an (unlikely) erroneous synchronizing operation.

7.2.4 Classification

As the normal operating frequency of power transformer circuit breakers is low, Class M1 is relevant. In the relatively few cases with high operating frequency, Class M2 may be applied.

Extended electrical endurance is not required for power transformer circuit breakers since relatively few short-circuit current interruptions are associated with this duty. Class E1 is sufficient.

7.3 Capacitor/filter circuit breakers

Switching of capacitor or filter banks is a relatively rare application, and involves only about 5% of all circuit breakers. There are, however, increasing needs to generate reactive power in order to improve system power factors, reduce transmission losses, and minimize voltage variations. There are also increasing requirements for improvement of power quality. As a result, the number of shunt capacitor and filter bank installations is steadily growing.

7.3.1 Recovery voltage and voltage factors

In general, the recovery voltage at interruption of capacitive current has a (1-cos) wave-shape, as described in Section 3.6. The section also gives information about the capacitive voltage factors k_c to be applied when performing single-phase tests as a substitute for three-phase tests. The following values apply:

k_c = 1.0 for capacitor banks with earthed neutral in systems with solidly earthed neutral
k_c = 1.4 for capacitor banks with isolated neutral

The recovery voltage of a filter bank may not follow a (1–cos) waveshape, but may include harmonic components. Therefore, the recovery voltage may have a shape as indicated in Figure 7.1. This needs to be considered when making the choice of circuit breaker. The voltage waveshape as indicated in Figure 7.1 might cause occasional reignitions that may be acceptable in order to obtain an economical solution. If they are not acceptable, a circuit breaker of higher rating should be chosen.

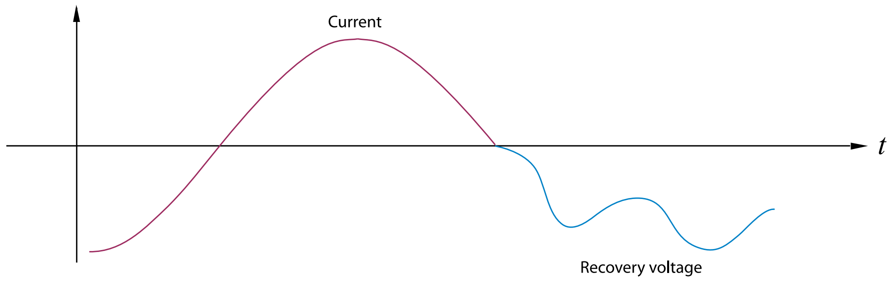


Figure 7.1 Typical recovery voltage for filter bank circuit breaker

The reactors that are often used for limitation of inrush currents to capacitor banks are normally of air-insulated type, and have low inductances and stray capacitances. Therefore the transient recovery voltages associated with the reactors on clearing short-circuits between the reactor and the capacitor bank are fast-rising with significant amplitudes. This may have to be considered when choosing appropriate circuit breakers.

7.3.2 Inrush current

The purpose of the current limiting reactors is to limit the inrush current on energizing to amplitude and frequency that can be handled by the circuit breakers (and also other equipment, including the capacitor banks). The limiting values specified in IEC 62271-100 are 20 kA$_{peak}$ at 4.25 kHz.

If a fault (short-circuit) occurs on the network in the vicinity of a capacitor bank, there will be outrush current flowing from the capacitor bank to the fault, of similar magnitude and frequency as the inrush current. Such outrush current needs to be considered for all other circuit breakers connected to the same busbar as the capacitor bank(s).

Controlled switching is an efficient method for limitation of inrush currents at energizing, making the current limiting reactors superfluous. However, since the outrush currents are not related to any switching action of the capacitor bank circuit breaker, they are not affected by controlled switching schemes. For this reason current limiting reactors are often used, even when controlled switching is applied.

7.3.3 Rating and classification

The network frequency has a major influence on the (1-cos) recovery voltage, and therefore on the risk of restrikes. 60 Hz applications are considerably more severe than 50 Hz applications.

The standard value of rated normal current for capacitor bank circuit breakers is 400 A. Higher values than 400 A do not pose a problem for modern circuit breakers.

Capacitor banks and filters provide a low-impedance path for the flow of harmonic currents, and therefore the power frequency current is normally modified to include the effect of the harmonics. A multiplier of 1.1 is generally used for a solidly earthed neutral bank and 1.05 for isolated neutral.

Circuit breakers for capacitor banks and filters are often switched regularly, e.g. on a daily basis. This means that the circuit breaker will have to cope with many operations, and Class M2 and C2 are recommended. The expected number of short-circuit interruptions is low, and electrical endurance class E1 is generally appropriate.

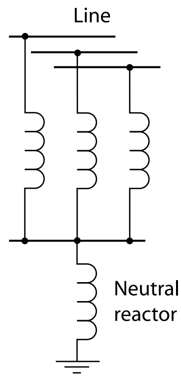
7.4 Shunt reactor circuit breakers

From a system point of view, an overhead transmission line conducting low current will behave as a capacitive load, and generate reactive power. For networks with long EHV (Extra High Voltage > 245 kV) transmission lines the result may be unacceptably high system voltages and power losses. In order to avoid this situation, shunt reactors are often used in such systems. The shunt reactors will consume reactive power and thereby counteract the effect of the lightly loaded overhead lines. In large systems the optimal solution is often some permanently connected shunt reactors, together with some shunt reactors that are energized only during periods with low active power flow in the system (typically night time and weekends).

Shunt reactors are installed in substations, and connected in any of the following three ways:

a. Line connected
The shunt reactor is connected directly to the end of an overhead line, in most cases simply by means of a disconnector. The line with its shunt reactor is then treated as a unit, and may be switched in and out by means of the line circuit breaker. For added switching flexibility the shunt reactor can be connected through a dedicated circuit breaker. At line faults, different operating procedures may exist with respect to the switching of the reactor circuit breaker. During a line fault the reactor breaker is normally not operated, but exceptions exist.

In EHV systems, the line circuit breakers will often perform single-pole switching and reclosing in case of line faults. In this case it is advantageous to equip the shunt reactor with a neutral reactor, connecting the star-point to earth. This arrangement helps to minimize residual current at the earth fault location during the time interval when the circuit breaker pole is open. This helps to extinguish the current and get rid of the fault.



b. Busbar connected
The shunt reactor is switched by a dedicated shunt reactor circuit breaker. Lines connected to the substation can be switched in and out without affecting the operation of the shunt reactor.

c. Connected to the tertiary winding of a power transformer
In this case the shunt reactor is connected at rather low voltage and by a dedicated reactor circuit breaker. The reactor (often air-core reactor) and the circuit breaker can be relatively inexpensive, but it is a disadvantage that access to the reactor requires that the power transformer is in service. In addition, the reactor current will be high, causing relatively high electrical wear of the circuit breaker contacts at switching operations.

7.4.1 Operating conditions

Under normal switching conditions the stresses during interruption are such that there is a low thermal interrupting stress due to the fact that the current most often is low. The dielectric stress, however, will be high and will appear very soon after current zero. The dielectric stress across the circuit breaker is steep and has a peak value typically about 2.3 p.u. at interruption of grounded shunt reactors having magnetic independent phases. For more detailed information see Section 3.7.1.

For a successful interruption, the arcing time of the circuit breaker pole must typically exceed a minimum arc duration of 4 - 7 ms (depending on the circuit breaker

properties in combination with the actual load conditions). For arc durations shorter than the application-specific minimum arcing time, the circuit breaker will reignite at the first current zero after contact separation.

Due to the very high frequency in the reignition loop it is most likely that the reigniting pole will not interrupt until the very next power frequency current zero.

7.4.2 Reignitions

Reignitions may lead to high overvoltages, and due to their steepness, especially in SF_6 circuit breakers, they are judged much worse to the system compared to chopping overvoltages. Fast voltage changes are also causing additional stresses on the reactor insulation due to an uneven voltage distribution. Circuit breakers must be designed to withstand reignitions, that can never be avoided at random operation.

7.4.3 Elimination of reignitions

A well-proven method to avoid reignitions is to control the contact opening of the circuit breaker with respect to the phase shift of the current (see ABB Controlled Switching, Buyer's and Application Guide). By means of controlled opening, all poles of the shunt reactor circuit breaker can be given a sufficiently long arcing time to ensure reignition-free interruption.

In addition to controlled opening, controlled closing can also be implemented to minimize the zero sequence current during energizing of the shunt reactor.

It is strongly recommended to use controlled switching for dedicated shunt reactor circuit breakers. The switching transients will be minimized at the same time the circuit breaker maintenance intervals will be prolonged, compared to the situation without controlled switching.

The preferred values of shunt reactor current given in IEC 62271-110 cover typical reactor sizes for the applicable voltage levels. For smaller reactors, the chopping overvoltage will increase and therefore cause longer arc duration to ensure re-ignition free interruption. For implementation of controlled switching, it is necessary to treat any installation with reactors smaller than 50 Mvar separately.

7.4.4 Shunt reactor switching tests

Shunt reactor switching tests are described in IEC 62271-110 and give guide-lines for testing. When performing single-phase tests as a substitute for three-phase tests, the following voltage multiplying factors apply:
- 1.0 for full pole tests of circuit breakers rated 245 kV and above
- 1.5 for full pole tests of circuit breakers rated 170 kV and below

7.4.5 Classification

The normal operating frequency of shunt reactor circuit breakers is high, often daily. This means that the circuit breaker shall be tested for class M2.

For circuit breakers switching shunt reactors connected to a tertiary winding of a transformer, it may be wise to ensure that the circuit breaker complies with the requirements for electrical endurance class E2.

7.5 Bus couplers

In many substation configurations, circuit breakers are placed between different busbars, or between different sections of the same busbar. These bus couplers are normally switched relatively seldom, and are mainly used for transfer of current from one busbar (section) to another, e.g. in connection with maintenance activities. Short-circuit interruption will only occur in case of busbar faults or in backup situations, if the primary circuit breaker fails to interrupt.

Generally, Classes M1, C1 and E1 are sufficient for circuit breakers used for bus coupler applications. The rated normal current may need to be relatively high (same as for the busbar).

7.6 Special applications

In addition to the applications indicated under Sections 7.1 – 7.5, special applications may exist for other types of systems or for other types of switching conditions in normal systems. These applications are not within the scope of the circuit breaker standard IEC 62271-100. The technical requirements and specifications for these applications are therefore often subject to agreement between the manufacturer and the user.

In many cases however, the existing requirements of IEC 62271-100 can be utilized for special applications but also modified for the purpose of the actual system or switching conditions.

7.6.1 Railway applications

Networks intended for railways are, unlike conventional networks, two-phase systems. In general, the voltage is supplied through a transformer with its centre tap earthed on the HV side. Each pole of the two-pole circuit breaker will therefore be subject to $U_r/2$, where U_r is the rated voltage between phases.

The transient recovery voltages for two-phase systems are usually calculated with the same approach as given in IEC 62271-100 (i.e. amplitude factors, RRRV, Rate of Rise of Recovery Voltage, etc.) but with a first-pole-to-clear factor k_{pp} of 1.0, resulting in significantly lower dielectric stresses than that of a three-phase system.

7.6.1.1 Railway applications with a power frequency less than 50 Hz

Some countries utilize a network system for railways based on a power frequency of 16 2/3 Hz or 25 Hz. This is mainly for historical reasons since it was, at the end of the 19th century, easier to manufacture electrical motors for lower frequencies.

With a lower power frequency, the current zeroes will occur less frequently compared to a 50 or 60 Hz system. Since the circuit breaker can only interrupt the current at a current zero, the arcing times, and consequently the generated energy in the interrupter, will be significantly longer (higher) than that of a 50 or 60 Hz system.

Usually, a modification of the contact travel characteristics is required, in order to maintain the blast pressure up to the final current zero.

On the other hand, the low frequency reduces the stresses associated with other switching conditions, e.g. capacitive switching, di/dt at short-circuit interruption, thermal stresses when interrupting short-line faults, etc.

7.6.2 Series capacitor by-pass switches

Although series capacitor by-pass switches sometimes utilize the same or similar design as that of a conventional circuit breaker, the application is completely different. The by-pass switch is part of the protective equipment of series capacitor banks, together with non-linear Metal Oxide Varistors (MOV) and (if applicable) protective spark gaps, and is placed in parallel with the series capacitor bank.

The main purpose with the by-pass switch is to deliberately by-pass and insert the series capacitor (planned operation) and for protective by-passing of the series capacitor in case of faults.

Hence, under normal service conditions when the series capacitor is connected in series with the overhead line, the by-pass switch is in open position and always prepared to by-pass the series capacitor bank in case of faults or any planned operations.

The main stresses related to switching of by-pass switches are the following:

a. By-pass making of series capacitor
The by-pass switch must be able to by-pass the series capacitor bank when it is precharged to its protective level (limiting voltage of the overvoltage protector) and consequently withstand the associated inrush current from the capacitor bank superimposed on the line fault current.

b. Insertion of the series capacitor
The by-pass switch must be able to transfer the load current from the by-pass circuit path to the series capacitor path and withstand the associated recovery voltage, with peak values of up to its protective level, without restriking.
In addition, the by-pass switch must be able to carry the rated current and the rated short-circuit current in closed position, as well as to withstand the overvoltages specified across open gap and phase-to-earth.
It should be noted, however, that the by-pass switch is not intended to interrupt short-circuit currents which may occur in the system.
IEC 62271-109 is applicable for ac series capacitor by-pass switches.

7.6.3 HVDC filters

HVDC ac filters are intended to supply reactive power to the network and to reduce the amplitude of harmonics on the voltage of the ac network.

The filter circuit breakers may therefore be subjected to frequent operation since the need for reactive power compensation may change several times per day.

During these planned operations (normal conditions), the stress on the circuit breaker is similar to that of switching of a capacitor bank with earthed neutral, i.e. a moderate recovery voltage when de-energizing the filter bank. The inrush currents during energizing are usually fairly low since the filters contain inductances in order to tune the filters for the correct frequencies. Furthermore, it is common to utilize controlled switching for energizing of filter banks.

Significantly higher stresses may be obtained when a fault occurs on the ac line with a consequent tripping of the converter and disconnecting of the faulty line. In this case, overvoltages may appear which makes it necessary to disconnect the filters from the bus. The overvoltages on the bus will naturally result in significantly higher recovery voltages than those seen during normal switching conditions.

In addition, the high amount of harmonics on the supply voltage may create higher RRRV (Rate of Rise of Recovery Voltage).

Typical values of the highest peak of the recovery voltage are in the range of 2.8 – 3.2 p.u.

System studies are usually performed as the basis for the technical requirements for filter bank circuit breakers. The results should be subject to a statistical evaluation in order to define the probability of the most severe switching cases.

7.6.4 SVC (Static Var Compensator)

The SVC can dynamically provide reactive power compensation to the network by means of Thyristor Controlled Reactors (TCR) or Thyristor Switched Capacitors (TSC). The SVC is usually installed at a significantly lower voltage than the main bus, fed through an SVC transformer.

In some cases circuit breakers are installed in the TCR or TSC branches. These circuit breakers are generally infrequently operated, but the low voltage will result in very high requirements for the rated current, usually in the range of 2,000 – 4,000 A, and very high short-circuit current carrying capability. In addition, the harmonics should be taken into account for the continuous current capability.

Some installations also require Mechanically Switched Capacitor banks (MSC) in parallel to the thyristor controlled branches. The combination of frequent operations and high load currents (including high frequent inrush currents) may require significantly higher capability than that normally required for these voltages.

7.7 Instrument transformers and relays in combination with live tank circuit breakers

When comparing the properties of live tank and dead tank circuit breakers, the location of adjacent current transformers is sometimes a concern.

For a dead tank circuit breaker, ring-core current transformers are placed on the bushings. Normally there are current transformers on both sides of the circuit breaker, and the two sets of transformers are applied to give overlapping protection zones. With the two sets it is also possible to detect earth faults/short-circuits within the dead tank circuit breaker itself, in the same manner as for a power transformer (differential protection). The possibility of such internal faults cannot be ruled out.

For a live tank circuit breaker, a single set of current transformers is used, and placed on either side of the circuit breaker. In a live tank design, the risk of earth faults or internal short-circuits may be ruled out, and there is no need for a duplication of the transformers.

A thorough comparison of the two alternatives shows that a dead tank circuit breaker with current transformers on both sides, and a live tank circuit breaker with current transformers on one side, have identical, or almost identical, function with regard to the relay protection.

7.8 Controlled switching

There are several important circuit breaker applications where random closing or opening instants may lead to severe voltage and current switching transients. These transients occur in the main circuits, but may also induce transients in control and auxiliary circuits, as well as in adjacent low voltage systems. The switching transients are associated with a variety of dielectric and mechanical stresses on the high-voltage equipment, and may cause gradual or immediate damage to the system or the equipment. Induced transients may lead to a variety of disturbances, e.g. in substation control and protection systems, computers and processors, or telecommunications.

Controlled switching is a method for eliminating harmful transients via time-controlled switching operations. Closing or opening commands to the circuit breaker are delayed in such a way that making or contact separation will occur at the optimum time instant related to the phase angle. By means of Switchsync™ controllers, both energizing and de-energizing operations can be controlled with regard to the point-on-wave position, and no harmful transients will be generated.

The subject of controlled switching is dealt with in detail in ABB Controlled Switching, Buyer’s and Application Guide.

8. Standards and tests

8.1 Standards

The major international standards for circuit breakers are IEC[1] and ANSI[2]/IEEE[3]. In addition to these standards, there also exist several region-specific standards often based on IEC and ANSI requirements.

The USA-based standards were originally developed and intended for use in the USA. Over the last 15 years a gradual change has taken place in the IEEE, and now there is a genuine interest in harmonizing the IEC and IEEE standards.

1. International Electrotechnical Commission
2. American National Standards Institute
3. The Institute of Electrical and Electronics Engineers, Inc.

8.1.1 IEC

Some years ago, the former standard IEC 60056 was replaced by the now valid IEC 62271-100 “High-voltage alternating current circuit-breakers.” One main objective when forming the -100 circuit breaker standard was to raise the requirements related to switching of capacitive loads, since service experiences had shown they were insufficient. Other changes were implemented at the same time. The capacitive switching classes C1 and C2 were introduced together with the mechanical endurance classes M1 and M2.

IEC has published several standard parts with the number IEC 62271 as a base. The list below shows some of the standard parts most relevant for the circuit breakers, old names are also listed:

IEC 62271-Part	Title	Old name
-1	Common specifications	IEC 60694
-100	High-voltage alternating current circuit breakers	IEC 60056
-101	Synthetic testing	IEC 60427
-108	High-voltage ac disconnecting circuit breakers for rated voltages of 72.5 kV and above	-
-110	Inductive load switching	IEC 61233
-300	Guide for seismic qualification	IEC 61166
-302	Guide for short-circuit and switching test procedures for metal-enclosed and dead tank circuit breakers	IEC 61633
-303	Use and handling of sulphur hexafluoride (SF_6) in high-voltage switchgear and Controlgear	IEC 61634

Table 8.1 Examples of IEC Standards for high voltage circuit breakers

IEC refers to CIGRE Technical Brochures 304 and 305 to provide background information concerning facts and figures, and to give a basis for specifications. In a similar manner, the American standards refer to IEEE application guides.

8.1.1.1 Time definitions according to IEC

One very useful section of IEC 61271-100 describes the circuit-breaker-related time definitions. The most frequently-used time definitions are shown below.

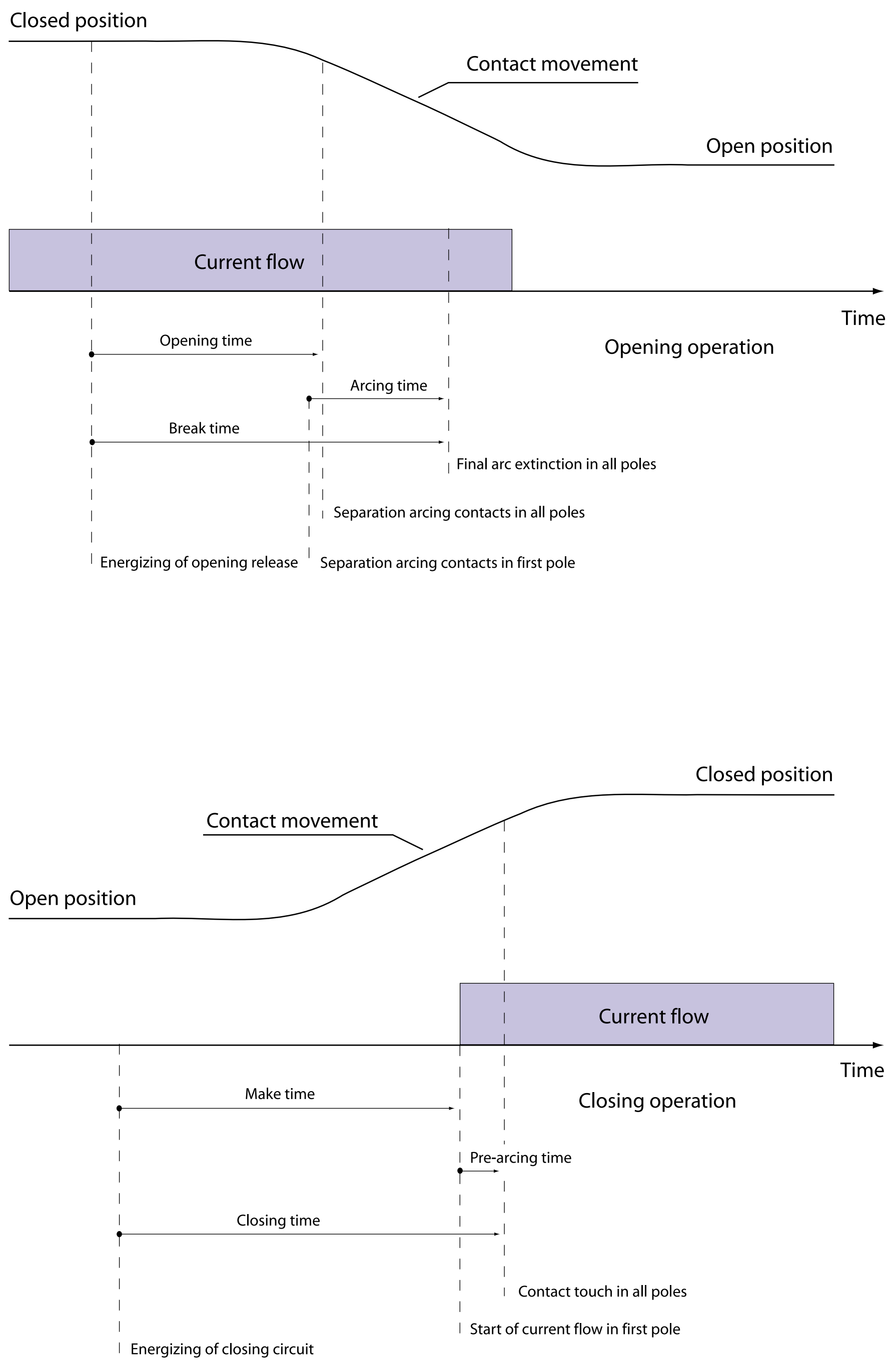


Figure 8.1 Time definitions during opening and closing, according to IEC

8.1.2 ANSI/IEEE

The standardization process for circuit breakers in the USA has changed significantly in recent years. Previously, several organizations were involved, each having its own standards: IEEE, ANSI and NEMA (National Electric Manufacturers Association). Today all responsibility for standards development on circuit breakers lies with the High Voltage Circuit Breaker Subcommittee (HVCB) of the IEEE PES (Power & Energy Society) Switchgear Committee.

The American standard institute ANSI has historically reviewed standards issued by IEEE. After approval, the standards had been issued as ANSI/IEEE standards. Since IEEE now has the responsibility for standard development, all new standards will be IEEE standards.

A number of documents has the status of standard (S), others of application guides (G). The latter do not contain mandatory requirements.

Standard	Title	S or G
C37.04-1999	Rating structure	S
C37.06-2000	Ratings	S
C37.06.1-2000	TRVs for transformer limited faults, trial use standard	S
C37.09-1999	Testing	S
C37.010-2005	Application guide – General	G
C37.011-2005	Application guide – TRVs	G
C37.012-2005	Application guide – Capacitive current switching	G
C37.015-1993	Application guide – Shunt reactor switching	G
C37.016-2007	Circuit-switchers	S
C37.081-1981	Synthetic testing	G
C37.082-1982	Sound pressure level measurement	S
C37.083-1999	Synthetic capacitive current switching tests	G
C37.10-1995	Guide for diagnostics and failure mode investigation	G
C37.10.1-2000	Guide for the selection of monitoring	G
C37.11-2003	Electrical control	S
C37.12-1991	Guide for the specification	G
C37.12.1	Guide for instruction manual content	G

Table 8.2 Examples of IEEE Standards and Guides for HV circuit breakers

8.2 Circuit breaker testing

Before a new circuit breaker type is released, numerous tests are performed to verify that the circuit breaker complies with the requirements of the international standards. When the design of the circuit breaker has been finalized, type tests are performed on some of the first manufactured specimens. Type tests consist of a large number of tests specified by the international standards. Type tests may be performed at the testing facilities of the manufacturer or at other (independent) laboratories.

8. Standards and tests

Type testing is a “must” for circuit breakers. It is a verification that the circuit breaker will be able to handle the stresses in the network in which it will be installed. At the same time it is an official verification of the ratings that the manufacturer has assigned to the circuit breaker.

Type tests consist of the following tests (IEC 62271-100):
- Dielectric tests
- Radio Interference Voltage (RIV) tests
- Temperature rise tests
- Measurement of the resistance of the main circuit
- Short-time current and peak withstand current tests
- Mechanical and environmental tests
- Making and breaking tests

Of the type tests, the making and breaking tests are the most comprehensive, since they involve tests on the circuit breaker at different current levels and different TRV’s to cover the different fault cases as described in Section 3. Because of the electrical power required and the special equipment involved in these tests, making and breaking tests are the most expensive tests performed on a circuit breaker.

Most of the type tests lead to significant wear and the circuit breakers cannot be delivered to customers after the tests. Several circuit breakers will be needed to complete one set of type tests for a circuit breaker type.

Routine tests are performed on each circuit breaker manufactured, with the purpose of revealing faults in material or assembly.

8.3 Type tests

In this section a brief description is given of the different type tests that are required by IEC 62271-100. Major differences between IEC and IEEE standard C37.09 are highlighted.

8.3.1 Dielectric tests

In a dielectric test, the circuit breaker is exposed to the different types of overvoltages as described in Section 6 (lightning impulse, switching impulse and power frequency).

In addition to the tests on the circuit breaker pole, the control wiring shall be subjected to a 2 kV, 1 min. power frequency withstand test in accordance with IEC. The test voltage in accordance with IEEE is 1,500 V during one minute, or alternatively 1,800 V during one second.

8.3.2 Radio Interference Voltage (RIV) tests

RIV tests are performed in order to establish the degree to which the circuit breaker interferes with radio communication when energized.
For further details see Section 6.4.3.1.

8.3.3 Temperature rise tests

In a temperature rise test on the main circuit, the rated normal current is conducted through the circuit breaker and the temperature rise (difference between the measured and the ambient temperature) of the crucial parts (contacts, connections and terminals) is measured by means of suitable temperature sensors. See also Section 5.2.

The test duration is dependent on when the temperature of the circuit breaker has stabilized and reached a steady state condition. This requirement is, according to IEC, considered to be fulfilled when the temperature increase is less than 1 K per hour. IEEE states that the temperature shall not change by more than 1 K as indicated by three successive readings at 30 min. intervals.

Gas-filled circuit breakers should be filled to a pressure equal to the specified minimum pressure (lock-out pressure) in accordance with IEC 62271-1. IEEE states that the test shall be performed under usual service conditions (i.e. rated pressure).

The limits of the temperature rise of the parts of the circuit breaker are given in IEC 62271-1, Table 3 and in IEEE C37.04 Table 1.

In addition to the temperature rise test on the main circuit, IEC requires a temperature rise test to be performed on the auxiliary equipment (coils, motors etc.). The circuit breaker is operated 10 times in rapid succession (minimal time between operations), after which the temperature rise is measured through resistance measurement.

8.3.4 Measurement of the resistance of the main circuit

Resistance measurement of the main circuit is performed before and after the temperature rise test. A dc-current of at least 50 A is fed through the circuit breaker and the voltage drop between the terminals is measured. The difference between the resistance measured before and after the temperature rise test is limited to ± 20%.

8.3.5 Short-time withstand current and peak withstand current tests

This test is performed with the circuit breaker in the closed position. The full short-circuit current is conducted through the circuit breaker for a specified duration. The circuit breaker is considered to have passed the test successfully if there is no mechanical damage and if the circuit breaker opens at the first attempt after the test with no significant change in opening time (i.e. no contact welding has taken place).

The preferred time duration is 1 s. As an alternative, value 3 s is given, although it seems very unlikely that a power system has the capability to sustain a full short-circuit current for such a long time without problems such as instability, emergency shut-down of large power plants, etc.

The peak value of the current shall be equal to 2.5 times the rms value of the rated short-circuit current for 50 Hz and a time constant of 45 ms. For 60 Hz this value is 2.6. See Section 3.1.2.

8.3.6 Mechanical and environmental tests

8.3.6.1 Mechanical operation test at ambient temperature

This test is commonly referred to as a mechanical endurance test. The circuit breaker shall be able to perform a specified set of operations, at rated minimum and maximum supply and control voltages. During the test the maintenance requirements specified by the manufacturer shall be taken into account. For the M1 class the operations at different voltages according to Table 8.3 shall be performed for the M2 class this set of operations is repeated five times. The total number of CO operations is 2,000 for class M1 and 10,000 for class M2.

Operating sequence	Supply/control voltage and operating pressure	Number of operating sequences	
		Circuit breakers for auto-reclosing	Circuit breakers not for auto-reclosing
	Minimum	500	500
C - t_a - O- t_a	Rated	500	500
	Maximum	500	500
C - t - CO - t_a - C -t_a	Rated	250	-
CO - t_a	Rated	-	500

O	opening
C	closing
CO	a closing operation followed immediately (i.e., without any intentional time delay) by an opening operation
t_a	time between two operations which is necessary to restore the initial conditions and/or to prevent undue heating of parts of the circuit breaker (this time can be different according to the type of operation)
t	0.3 s for circuit breakers intended for rapid auto-reclosing, if not otherwise specified

Table 8.3 Number of operating sequences

IEEE requires 2,000 CO operations with no specified time between operations. Only a few operations need to be performed at the maximum and minimum limit of the rated operating voltage. In additional the circuit breaker shall, after the test, be capable of withstanding the maximum voltage across the open contacts.

The resistance of the main current path shall not be greater than 200% of the maximum value given by the manufacturer for a circuit breaker in new condition.

Furthermore, IEEE requires that a test shall be performed in order to prove that the transient voltage produced in the control circuit associated with the circuit breaker does not exceed 1,500 V.

Generally the class M1 is sufficient. For circuit breakers having a special duty that requires frequent operation (switching of capacitor banks, shunt reactors and filter banks), specification of the M2 class with 10,000 CO operations is recommended.

Figure 8.2 Circuit breakers at mechanical endurance test

8.3.6.2 Low and high temperature tests/tightness tests

The low and high temperature tests are not mandatory and are performed only upon agreement between manufacturer and user. The low temperature test is normally performed in combination with a tightness test.

Before the low temperature test, a number of characteristics and settings need to be recorded at ambient temperature T_A, such as timing, speed, tightness, etc.

The ambient air temperature is then decreased to the minimum specified value T_L. When the temperature has stabilized at the specified low temperature, a sequence of operations is performed at defined time intervals (see Figure 8.1). After 50 hours, the temperature shall then be raised until the ambient temperature of 20 °C is reached.

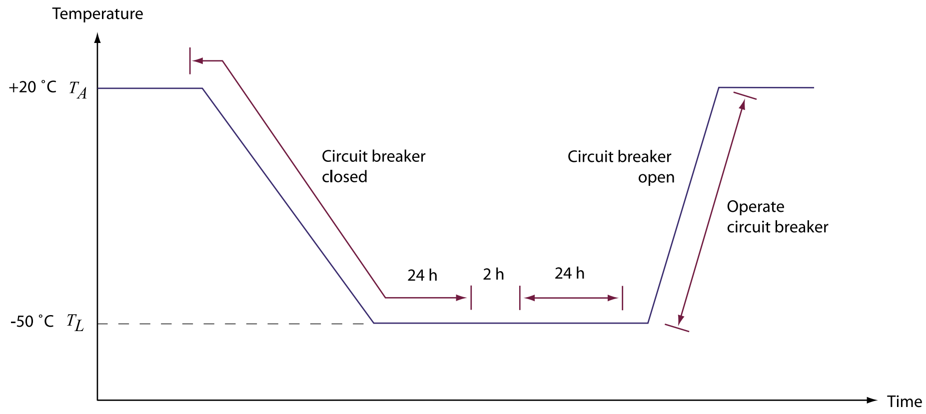


Figure 8.3 Test sequence for low temperature test at -50 °C

The preferred values of minimum ambient air temperature, according to IEC, are -10 °C, -25 °C, -30 °C and -40 °C. The min. ambient temperature -50 °C falls under special service conditions.

The accumulated leakage during the complete low temperature test shall be such that the lock-out pressure is not reached.

A well-designed circuit breaker will have extremely low or no leakage of gas during steady state conditions. However, small leakages can occur when operating at low temperatures, since the rubber in the sealing systems are harder and not able to respond quickly enough to the vibrations during operation.

IEEE specifies a similar low temperature test as IEC. However, only -30 °C is stated and the standard does not explicitly require a low temperature test. If testing facilities do not permit this verification, a test of important components at the low ambient temperature is sufficient.

8.3.6.3 High temperature test

The high temperature test verifies the operating characteristics of the circuit breaker at high temperature conditions. IEC 62271-1 states a maximum ambient temperature of +40 °C as normal service condition. +50 °C falls under special service conditions.

Normally the high and low temperature tests are combined into one test where the high and low temperature sequences are performed after each other in the same test set up. The test procedure for the high temperature test is very similar to the low temperature test. Figure 8.4 shows the different stages of the test.

IEEE specifies the normal maximum ambient temperature to +40 °C; no specific high temperature test is defined.

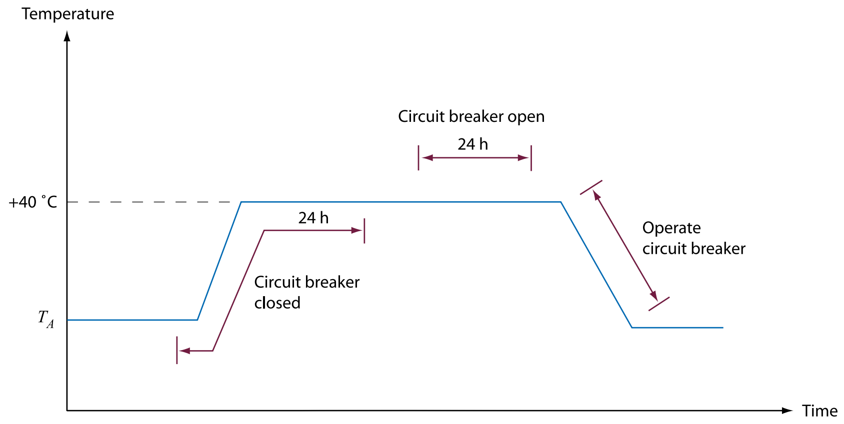


Figure 8.4 Test sequence for high temperature test

8.3.6.4 Humidity tests

According to IEC, the humidity test shall not be applied on equipment which is designed to be directly exposed to precipitation, for example primary parts of outdoor circuit breakers. It is also unnecessary where effective means against condensation are provided, for example in control cubicles with anti-condensation heaters.

Humidity tests are not specified by IEEE.

8.3.6.5 Ice tests

Tests under severe ice conditions are applicable only to circuit breakers having moving external parts. The ice coating shall be considered in the range from 1 mm up to, but not exceeding, 20 mm. If a circuit breaker is to be located where an ice coating exceeding 20 mm is expected, agreement should be reached between manufacturer and user as to the ability of the circuit breaker to perform correctly under such conditions.

IEEE does not require any test; however, it is stated that outdoor circuit breakers shall be capable of withstanding ice loading caused by up to 20 mm of ice.

8.3.6.6 Static terminal load test

The static terminal load test is performed to demonstrate that the circuit breaker operates correctly when loaded by stresses resulting from ice, wind and connected conductors. The static terminal load test is applicable to outdoor circuit breakers having a rated voltage of 52 kV and above. See Section 4.1.1.

The static terminal load test is performed only upon agreement between manufacturer and user. If the manufacturer by calculations can prove that the circuit breaker can withstand the stresses, no test needs to be performed.

IEEE states values of the statical load in IEEE C37.04, Clause 6.3.2. However, no test is required.

8.3.7 Making and breaking tests

The making and breaking tests are the most comprehensive type tests. The tests are intended to verify that the circuit breaker can handle the different switching stresses to which the circuit breaker can be exposed during normal service.

The preparations before the tests, different test methods and the characteristics of the different tests are described below.

8.3.7.1 Preparation for tests

Before all tests, the operational characteristics of the circuit breaker must be known. In order to check this, no-load tests are performed. No-load tests consist of different operating sequences at different operating voltages and pressures in the case of pneumatic and hydraulic operating mechanisms.

During the no-load tests the operating times and contact speeds are measured and reported. After the test sequence another set of no-load operations is performed, and the results of these shall, compared to the first ones show no significant change.

8.3.7.2 Single-phase/three-phase testing

According to this method, a single pole of a three-pole circuit breaker is tested single-phase. This is done by applying to the pole the same current and substantially the same power-frequency voltage which would be impressed upon the most highly-stressed pole during three-phase making and breaking by the complete three-pole circuit breaker under corresponding conditions.

To verify that the characteristics of a single phase of a circuit breaker correspond to the characteristics of a three-phase unit, a making and breaking test is performed. After the test, the behavior and travel characteristics are evaluated according to the requirements stated in 62271-100, Clause 6.101.1.1.

IEEE also gives provision for single-phase testing and states similar conditions as IEC, see IEEE C37.09 Clause 4.8.2.2.

8.3.7.3 Unit test/full pole test

Owing to limitations in the high power laboratories, full pole testing is not always possible, especially with the recent development of breaking units with a high voltage rating. In such cases unit tests, or half pole tests, may be performed. Unit tests are allowed if the requirements according to IEC 62271-100, 6.102.4.2 are fulfilled. For example, the following requirements must be fulfilled:

- the units of the circuit breaker shall be identical in shape, dimension and operating conditions
- the operating energy shall be adjusted in such a way that the contact movement does not differ from that of the full pole
- the voltage distribution between the breaking units must be considered. The test voltage shall be the voltage of the most highly-stressed breaking unit of the complete pole of the circuit breaker.

IEEE C37.09, Section 4.8.2.3.1 specifies the corresponding requirements for unit testing.

8.3.7.4 Direct tests

Direct tests are characterized by one source giving the correct current before interruption and the correct voltage stresses after the interruption (see Figure 8.5).

The nature of direct testing is rather simple. In the case of direct testing, the circuit breaker chooses the best current zero in which to interrupt. The setting of the initiation of the short-circuit as well as the contact separation is well-defined.

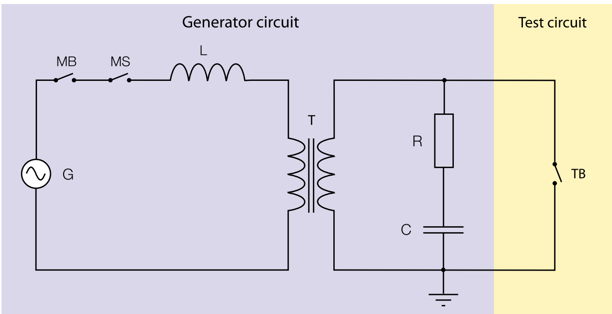


Figure 8.5 Single phase test circuit for direct test

G	Short-circuit generator
MB	Master circuit breaker
MS	Making switch
L	Reactor for limitation of short-circuit current
R, C	Oscillatory circuit for TRV
TB	Test circuit breaker
T	Transformer

When performing a CO operation, the circuit breaker will be correctly stressed at both the making and the breaking operation. After the interruption the recovery voltage shall be applied for 5 cycles.

Should the test circuit breaker fail to interrupt the current, the circuit is protected by a master circuit breaker, a circuit breaker able to interrupt within half a cycle. The short-circuit current is initiated by closing the making switch.

8.3.7.5 Synthetic testing

With the increasing voltage and current ratings of recently-developed circuit breakers, the total available short-circuit power of a high-power laboratory has to be increased accordingly. The investments in increasing short-circuit power are tremendous and would cause circuit breaker prices to be prohibitive. In order to still be able to perform the correct type tests on circuit breakers with the available short-circuit power, one possibility is open: performing synthetic tests.

A synthetic test circuit consists of separate high-current and high-voltage circuits (see Figure 8.6). During the short-circuit period, the short-circuit current will be fed from a short-circuit generator at a limited voltage. The voltage should have an amplitude of sufficient magnitude to prevent the arc voltage from influencing the short-circuit current.

When the current is interrupted, the high-voltage circuit will give the correct voltage stresses across the contact gap

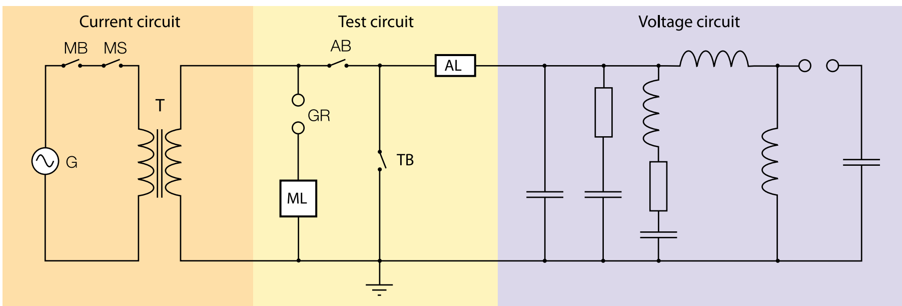


Figure 8.6 Principle of synthetic testing.

G	Short-circuit generator
MB	Master circuit breaker
MS	Making switch
TB	Test circuit breaker
AB	Auxiliary breaker
AL	Artificial line
GR	Spark gap
ML	Multi-loop re-ignition circuit

In order for the synthetic test to be valid, the test must subject the circuit breaker to realistic stresses, compared to those of a direct test. Requirements for the synthetic tests are stated in IEC and IEEE standards.

8.3.7.6 Summary of test duties

Test duties for the different switching cases are described by the standards; IEC states the following making and breaking tests:

Terminal faults	T10, T30, T60, T100s (symmetrical) and T100a (asymmetrical)
Short line faults	L90, L75 and (L60)
Out of phase tests	OP1 and OP2
Capacitive switching	LC1 and LC2 for capacitive line switching CC1 and CC2 for cable switching cases BC1 and BC2 for capacitor bank switching

In the following sections a brief description is given of the making and breaking tests required by IEC and IEEE.

8.3.7.7 Terminal fault

Terminal faults correspond to the stresses to which the circuit breaker will be exposed at a fault directly at, or in the vicinity of, the main terminals.

IEC requires tests with 10, 30, 60 and 100% of the rated short-circuit breaking current. A test with asymmetrical current is required only with 100% of the rated short-circuit breaking current.

IEEE requires tests with 10, 25, 50 and 100% of the rated short-circuit breaking current. Tests with asymmetrical current are specified at 10, 50 and 100% of the rated short-circuit breaking current.

IEEE traditionally uses a first-pole-to-clear factor of 1.5, irrespective of the earthing configuration of the network; however, in the latest edition of IEEE, harmonization towards IEC has led to the value 1.3 also being used. IEC specifies both 1.3 and 1.5 depending on the way the system is earthed.

8.3.7.8 Short-line fault

Both IEEE and IEC require the SLF tests to be performed at 90 and 75% of the rated short-circuit current. The surge impedance of the line is standardized to 450 Ω. The L60 test is generally not needed, only mandatory if certain results are obtained during the L90 and L75 tests, see IEC 62271-100, 6.109.4.

8.3.7.9 Out-of-phase making and breaking tests

IEC and IEEE do not deviate much in their requirements for out-of-phase making and breaking tests. IEC requires the test to be performed at 7.5 and 25% of the rated short-circuit breaking current. For those circuit breakers not having a critical current, the test at 7.5% may be omitted. The multiplication factors for the recovery voltage as well as for the TRV are depending on the earthing situation of the network and are 2.0 for earthed neutral systems and 2.5 for systems other than earthed neutral.

IEEE requires the test to be performed at 7.5 and 25% of the rated short-circuit breaking current, and the multiplication factor in all cases is 2.0. This is in contradiction to the first pole-to-clear factor of 1.5 used for the terminal fault tests, which suggests an unearthed system (or the presence of three-phase unearthed faults in an earthed system).

The out-of-phase test duty with 7.5% of the rated short-circuit breaking current may be used to prove the insulation coordination between the arcing contacts and the main contacts of, for example, an SF_6 circuit breaker.

8.3.7.10 Capacitive current switching

In previous editions of the standards, the definition “restrike free” was used. The occurrence of restrikes has been recognized as a statistical phenomenon and the standards have been changed. The level of restrike probability also depends on the service conditions (e.g. insulation coordination, number of operations per year, maintenance policy of the user, etc.).

With the IEC 62271-100, the capacitive switching classes C1 and C2, (low probability and very low probability of restrike) were introduced. For further details see Section 3.6.1.

IEC defines a series of tests that shall be performed at different filling pressures to qualify the circuit breaker for either C1 or C2 class, see Table 8.4.

Capacitive switching class	LC1	CC1	BC1	Pre conditioning test, T60
C1	Rated filling pressure	Rated filling pressure	Rated filling pressure	No
C2	Min. functional pressure	Min. functional pressure	Min. functional pressure	Yes

Table 8.4 Description of C1 and C2 tests

IEEE has also adopted the capacitive switching classes C1 and C2. The amendment C37.09a-2005 specifies basically the same test procedures as IEC.

8.3.7.11 Shunt reactor current switching tests

The test procedure and theory about the interruption of small inductive currents is given in more detail in IEC 62271-110. The aim of the laboratory tests is to determine the chopping number of the circuit breaker as well as the reignition behavior. The chopping number can be used to determine the overvoltages that will occur in an actual situation.

For shunt reactor applications with controlled switching, the reignition behavior of the circuit breaker will give information on how to properly set up the Switchsync™ controller.

IEEE Std C37.015-1993, "IEEE Application Guide for Shunt Reactor Current Switching," gives the IEEE requirements for shunt reactor switching.

8.4 Routine tests

Routine or production tests are for the purpose of revealing faults in material or assembly of the daily production of circuit breakers. Routine tests shall be performed on each apparatus manufactured. Routine tests consist, among others, of the following tests:

- Power frequency voltage withstand dry test on the main circuit
- Voltage withstand tests on the control and auxiliary circuits. IEC requires the test to be performed at 2,000 V, 1 min., IEEE requires the test to be performed at 1,500 V, 1 min
- Measurement of the resistance of the main circuit. The resistance of the main circuit is limited by IEC to 1.2 times the value obtained at the type test. IEEE states that the limit of the resistance of the main circuit shall be specified by the manufacturer.
- Mechanical operating times. The circuit breaker is operated a number of times at the limits of the control voltage, and during these tests the timing, speed etc. are checked against the values given by the manufacturer.

Furthermore, a number of other things are checked: compliance with the order specification, tightness, resistance of heaters and coils, etc. After verification the routine test report is provided to the customer as part of the order documentation.

8.5 Test reports

This section contains information regarding type and routine test reports. A brief description is given about the different independent test organizations.

8.5.1 Type test reports

The type test report shall describe the conditions during the test, the performance of the test and the result of the test. A summary of the tests by the manufacturer-assigned ratings and a specification of the tested object shall also be included.

A type test report shall contain the following minimum information:

- A general section containing the date of the test(s), report numbers, oscillogram numbers, etc.
- An identification of the tested apparatus (type, type designation, manufacture, dimension print, serial number, drawings, etc.).
- Ratings assigned by the manufacturer.
- Test conditions for each test.
- Description of test circuits, applied voltages, breaking currents, operational times of the circuit breaker, behavior and condition after the test.

8.5.2 Type test reports of independent laboratories

Sometimes a manufacturer may decide to have the circuit breaker performance verified by an independent test laboratory. This will give an official confirmation of the guaranteed performance of the circuit breaker. The tests performed at such laboratories are mainly short-circuit making and breaking tests.

8.5.3 STL organization

Type test reports from independent laboratories have different formats, depending on which laboratory issues them. Even the interpretation of the standards may differ from one laboratory to another. For this reason a number of laboratories have formed an organization with the objective of harmonizing test report formats, obtaining a uniform interpretation of IEC standards and harmonizing the measuring methods.

This organization is named STL, which stands for Short-Circuit Testing Liaison. The full members of this organization are:

ASTA BEAB	Certification Services	UK
CESI	Centro Elletrotecnico Sperimentale Italiano S.p.A.	Italy
CPRI	Central Power Research Institute	India
ESEF	Ensemble des Stations d'Essais à Grande Puissance Française	France
JSTC	Japanese Short-Circuit Testing Committee	Japan
KEMA		Netherlands
PEHLA	Gesellschaft für Elektrische Hochleistungsprüfungen	Germany and Switzerland
SATS	Scandinavian Association for Testing of Electric Power Equipment	Sweden and Norway
STLNA	Short-Circuit Testing Liaison of the Nations of the Americas	Canada, Mexico and USA

8.5.4 SATS organization

SATS Certification is an association of Scandinavian manufacturers, independent test laboratories and end user organizations. The objective of SATS Certification is to issue Type Test Certificates and Certificates of Type Conformity for electric power equipment based on tests carried out in laboratories accredited to ISO/IEC 17025.

SATS Certification is a signatory member to the STL Agreement and is thereby authorised to issue STLA Certificates.
The following laboratories are members of SATS:

ABB High Power Laboratory	Ludvika, Sweden
NEFI	Skien, Norway
NEXANS	Halden, Norway
SINTEF Energy Research	Trondheim, Norway
STRI AB	Ludvika, Sweden

9. Reliability, maintenance and life cycle costs

9.1 Failure statistics

Information about failures and failure statistics is important for both system operators and asset managers. Two types of statistics are used:

– System interruptions, i.e. loss of electrical power delivered to customers
– Equipment failures.

An equipment failure may or may not lead to a system interruption.

International (equipment) failure statistics for circuit breakers are collected and published by Cigré. Two types of failures are considered: major failures and minor failures. A major failure will result in an immediate change in the system operating conditions, e.g. the backup protective equipment will be required to remove the fault, or will result in mandatory removal from service within 30 minutes for unscheduled maintenance. A minor failure is a failure other than a major failure.

Examples of major failure categories are “does not open on command,” “opens without command,” “fails to carry current,” etc. Typical minor failures are small leakages of SF_6 or hydraulic oil.

The overall average major failure rate for SF_6 single pressure circuit breakers and rated voltages 63 – 800 kV published by Cigré is 0.67 failures/100 circuit breaker years (Final report of the second international enquiry on high voltage circuit breaker failures and defects in service, Cigré Technical Brochure No 83, 1994). A substantial share of the failures was caused by the operating mechanisms. Hydraulic and spring mechanisms had almost the same major failure rates, while the minor failure rate was much higher for the hydraulic mechanisms, due to oil leaks. The statistics do not give information about the performance of circuit breakers from individual manufacturers.

In general we recommend use of the Cigré failure statistics. They are based on a large population of circuit breakers from many countries around the world. The failures have been reported by the users (utilities, etc.) giving confidence that all failures are included.

9.2 Electrical and mechanical life

Assuming that the recommended inspection intervals have been adhered to and that the appropriate measures have been implemented, ABB circuit breakers will have a service life exceeding 30 years and 2,000 (Class M1) or 10,000 (Class M2) mechanical operations.

For each circuit breaker type, the maximum permissible electrical wear of the interrupters is approximately expressed by:

$$\sum n \cdot I^{k} = T$$

where

n	number of short-circuits
I	short-circuit current, kA (rms)
k	an exponent in the order of 1.8-2
T	A total permissible number, specific for each circuit breaker type

When using the expression, all short-circuit current levels are included in the summation, e.g. $20 \cdot 30^{n} + 30 \cdot 20^{n} + 40 \cdot 10^{n}$.

As an example, Figure 9.1 shows the maximum permissible electrical wear for LTB 72.5 - 170 D1/B.

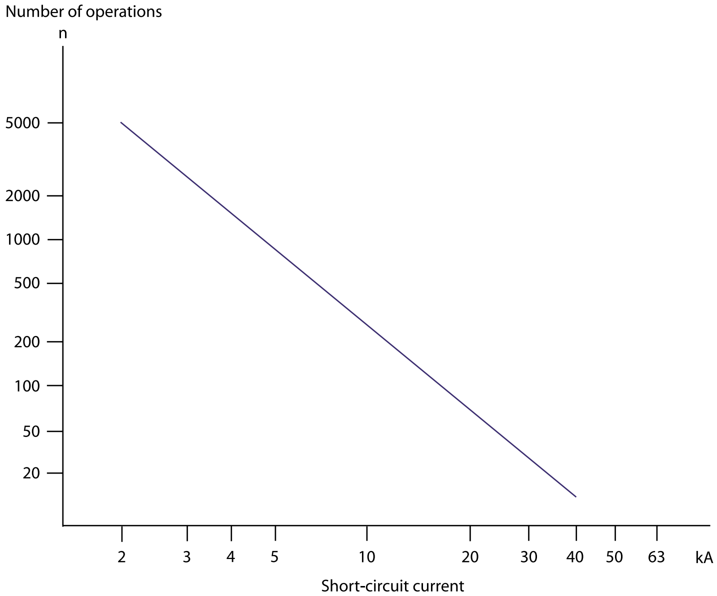


Figure 9.1. Maximum permissible electrical wear, $\sum n \cdot I^2$ = 20,000, for LTB 72.5 - 170 D1/B.

9.3 Maintenance

For each circuit breaker type, the Operating and Maintenance Instructions define time intervals and activities for the following types of maintenance:
- Ocular inspection
- Preventive maintenance
- Overhaul

Ocular inspections normally take place at 1-2 year intervals. The circuit breaker is kept in service.

Preventive maintenance is normally performed at 15-year intervals, and with the circuit breaker taken out of service. Shorter time intervals may be required if the circuit breaker reaches the maximum permissible electrical wear, or the maximum permissible number of mechanical operations. In the cases of frequent switching of capacitor banks, filter banks or shunt reactors, the number of permissible switching operations is higher for controlled switching operations (with Switchsync™) than for uncontrolled switching.

Overhaul of the circuit breaker should be performed after 30 years, or when the maximum permissible electrical wear or number of mechanical operations has been reached. The circuit breaker poles and mechanism are then normally removed, for fitting of new contacts and other worn parts.

It should be noted that users are increasingly replacing purely time-based maintenance schedules with condition-based maintenance. The schedules included in the operating and maintenance instructions consist of a combination of time-based and condition-based activities.

9.4 Condition monitoring

On-line condition monitoring may be applied in order to improve the reliability of circuit breakers, or to give guidance for condition-based maintenance. We recommend use of on-line condition monitoring in the following situations:
- Very important circuit breakers
- Circuit breakers in very remote substations, where manual inspections are costly and time-consuming.

The OLM condition monitor is described in Buyer’s Guide, Live Tank Circuit Breakers. The following parameters may be monitored: operating times, coil currents, contact travel (giving information about speed, overtravel and damping), motor current including spring charging time, and SF_6-density. Phase currents can be measured as an option to determine the accumulated electrical contact wear.

Conditions monitoring functions are integrated as a standard in Motor Drive operating mechanisms.

9.5 Life Cycle Costs

For a user, a circuit breaker has a certain purchase cost. In addition there will be costs for installation and commissioning, and maintenance during the lifetime. A life cycle cost (LCC) calculation considers all of these cost elements, and calculates a resulting present value. Costs for repairs after failures are also sometimes included, based on estimated failure rates. LCC calculations are useful, e.g. for comparison between different circuit breaker technologies.

Typical LCC calculations for ABB circuit breakers show that the cost contribution from maintenance and repair is relatively small compared to the initial cost (purchasing and installation). Figure 9.2 shows as an example the result of calculations for a circuit breaker type HPL 420B2. The time span was assumed to be 30 years, and the interest rate 5%. The maintenance portion includes the overhaul performed after 30 years.

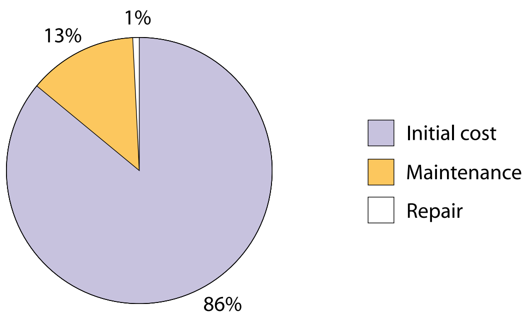


Figure 9.2. Result of LCC calculation for circuit breaker type HPL 420B2.

9.6 Environmental aspects

It is important that electrical equipment has the lowest possible impact on the environment and the surroundings.

In this context, the SF_6 gas in the circuit breakers and its possible contribution to the greenhouse effect, should be noted. SF_6 is a strong greenhouse gas, and its release to the atmosphere should be minimized. It is advantageous to decrease gas volumes and leakage rates as much as possible. Therefore, from an environmental point of view, a live tank circuit breaker, with its relatively small volume of SF_6 gas, is a better solution than a dead tank circuit breaker or GIS.

When a circuit breaker is overhauled or finally scrapped, the SF_6 gas should be carefully pumped out and stored. Such used gas from circuit breakers can, in the large majority of cases, be cleaned and recycled, either at site or at a gas manufacturer. In very rare cases, with extremely heavy contamination of the gas, it may be necessary to destroy the gas. Processes for such destruction of gas are well-established.

Switchgear Specification Manager (SSM)

ABB can provide a tool for creation of HV apparatus specifications, the Switchgear Specification Manager. SSM is a simple and safe software based on Microsoft Office. The program is divided in two parts: Input module and processing, based on Excel and output module based on Word.

SSM generates a complete specification, with:
- introductory, general parts
- technical description
- data schedule

Since the technical specification is generated in MS Word it can easily afterwards be edited to suit your own purpose.

Supported products

SSM supports high voltage AIS applications up to 800 kV. Supported products are:
- Surge arresters
- Instrument transformers
- Capacitors
- Circuit breakers
- Disconnectors
- Withdrawable & disconnecting circuit breakers

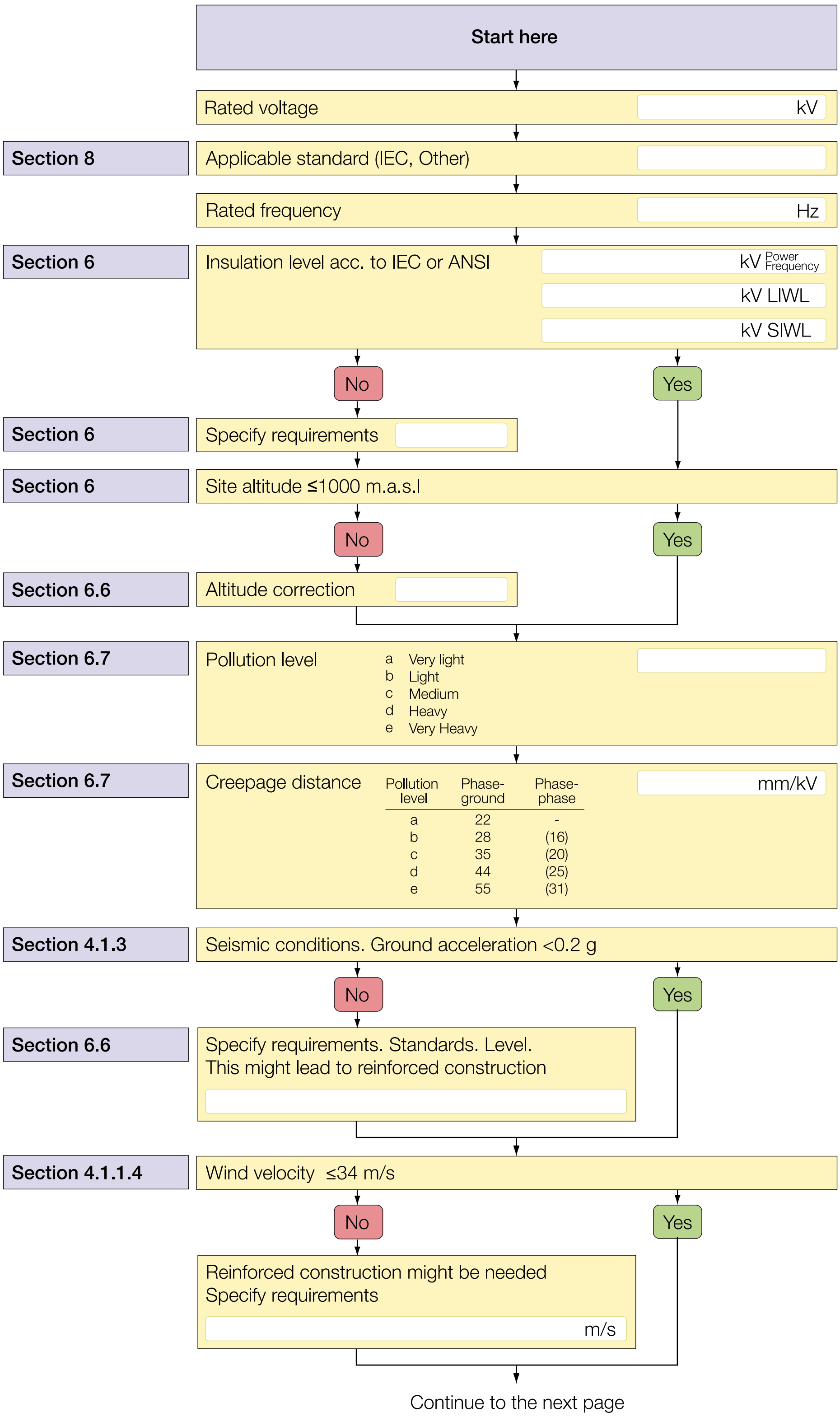
More information

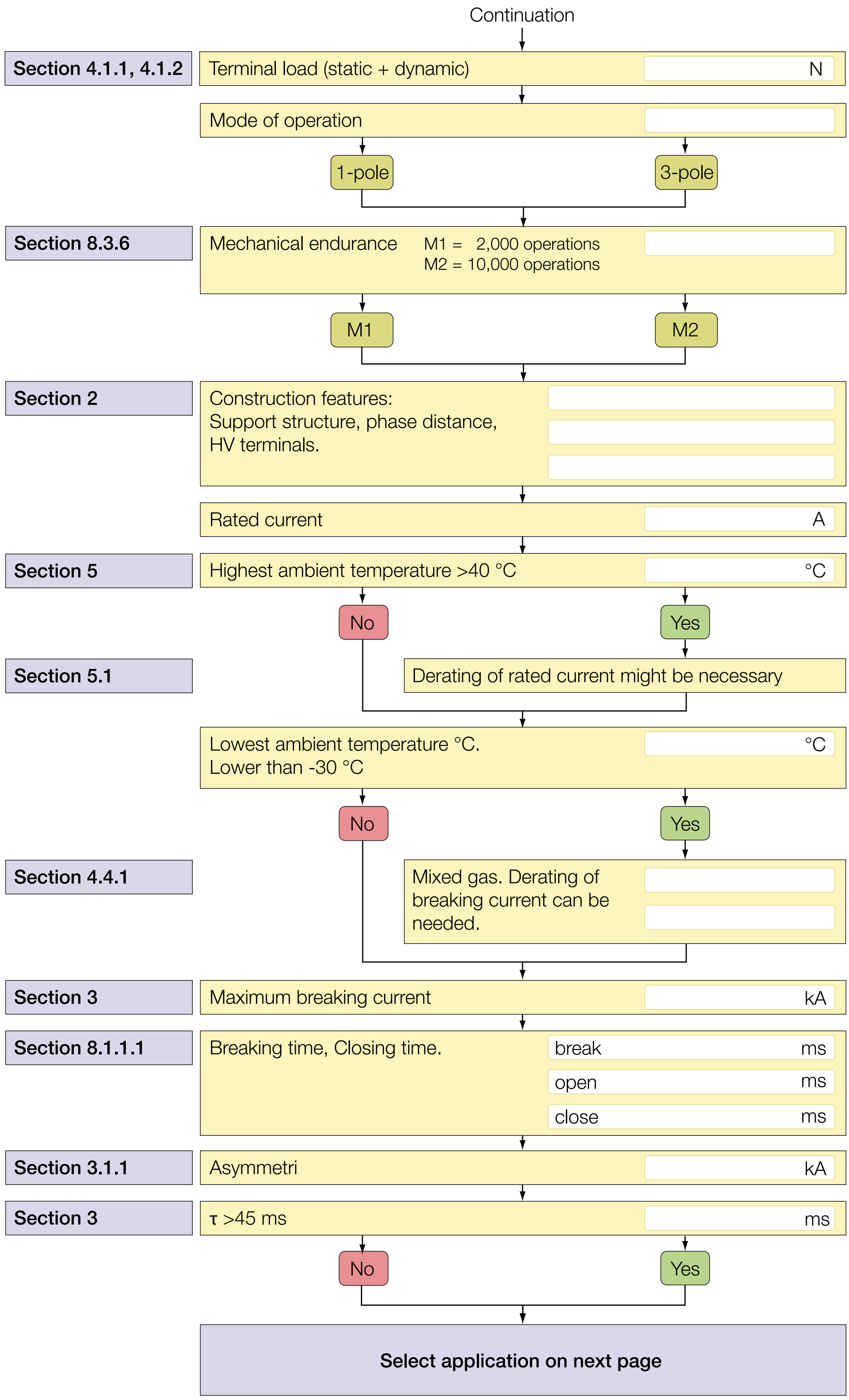
Please contact your local sales representative for more information about SSM.

Selection of circuit breakers

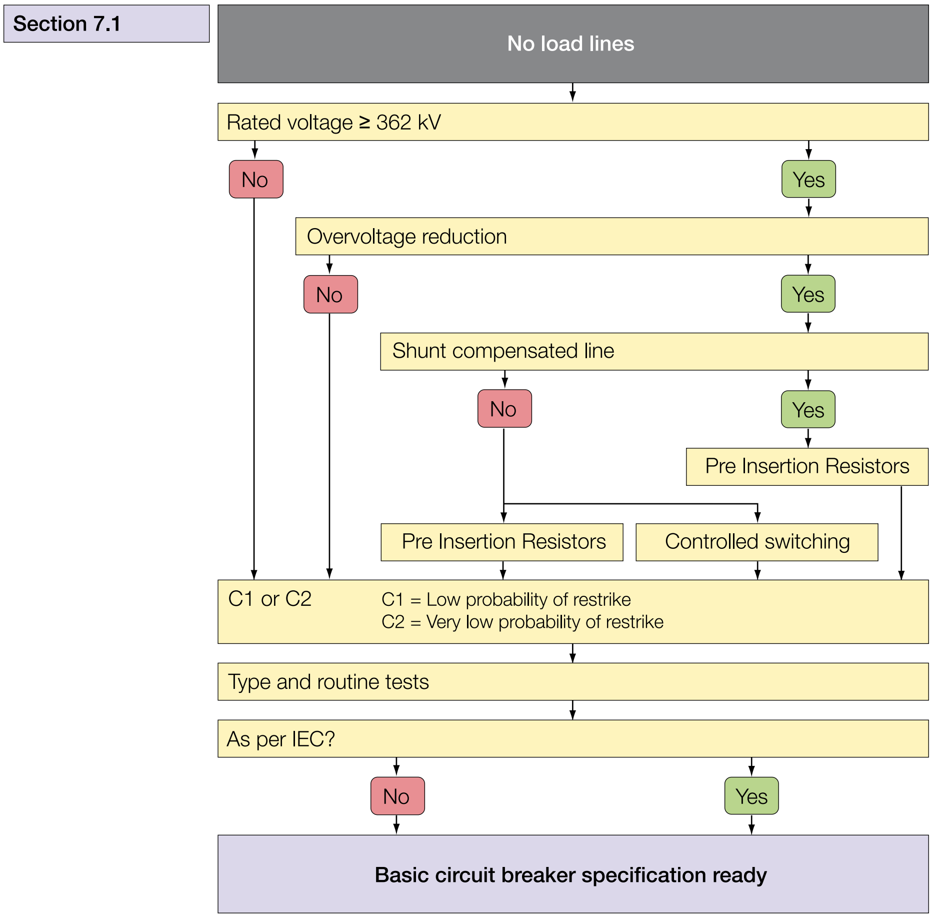
To get optimal function of a circuit breaker for the actual stresses it will see during its life time, relevant data for the specific application must be taken into consideration at the specification and selection of the circuit breaker. The selection diagrams on next page are provided as a tool and guide to identify the relevant information for the most common circuit breaker applications.

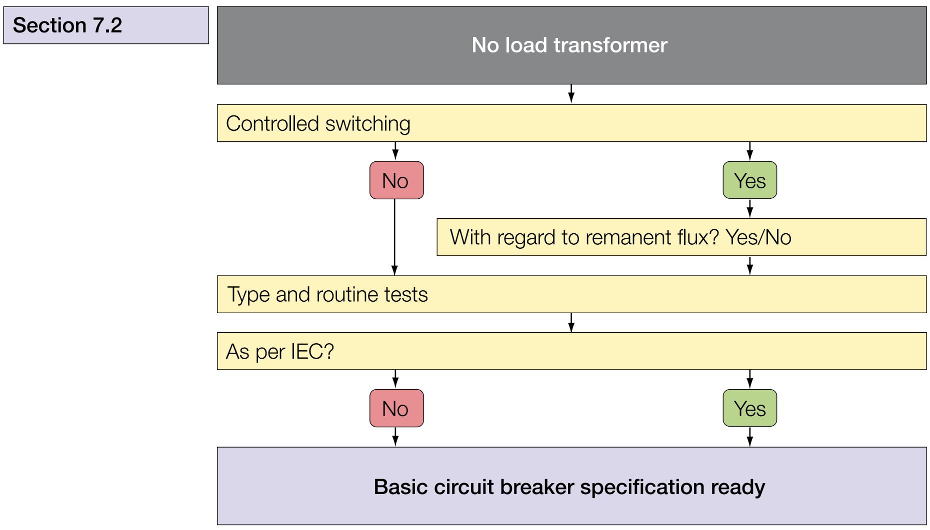
10. Selection of circuit breakers

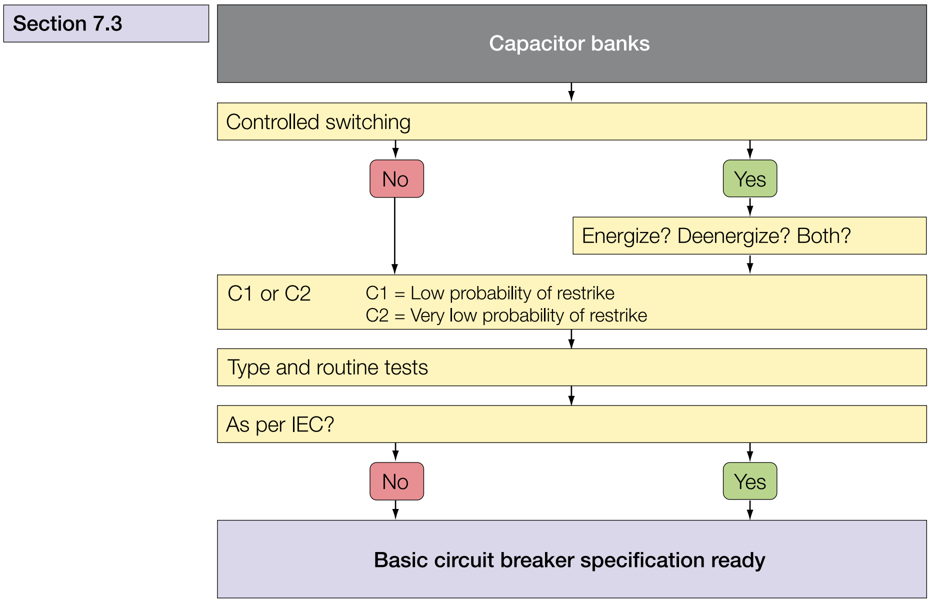


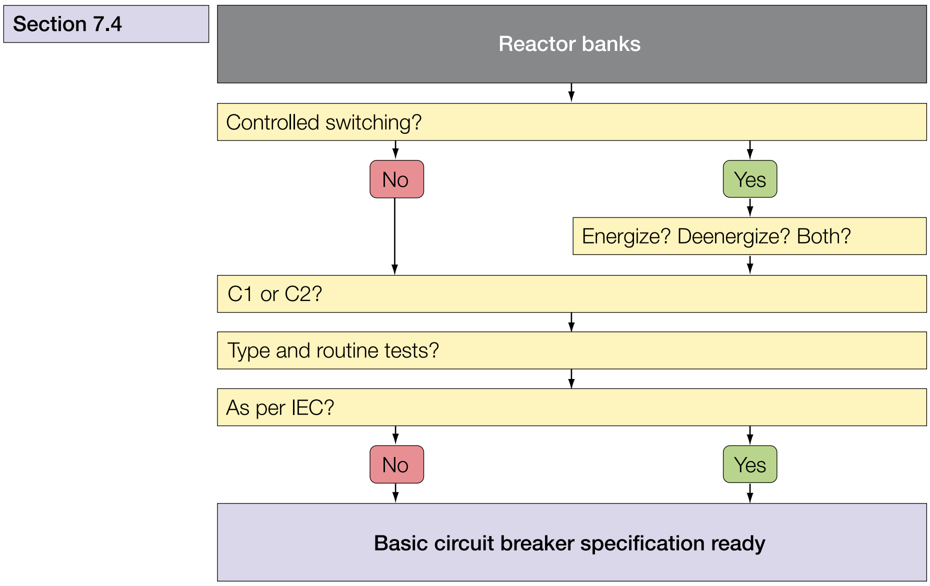

Continuation
Section 4.1.1, 4.1.2
Terminal load (static + dynamic)
N
Mode of operation
1-pole
3-pole
Section 8.3.6
Mechanical endurance
M1 = 2,000 operations
M2 = 10,000 operations
M1
M2
Section 2
Construction features:
Support structure, phase distance,
HV terminals.
Rated current
A
Section 5
Highest ambient temperature >40 °C
°C
No
Yes
Section 5.1
Derating of rated current might be necessary
Lowest ambient temperature °C.
Lower than -30 °C
°C
No
Yes
Section 4.4.1
Mixed gas. Derating of
breaking current can be
needed.
Section 3
Maximum breaking current
kA
Section 8.1.1.1
Breaking time, Closing time.
break
ms
open
ms
close
ms
Section 3.1.1
Asymmetri
kA
Section 3
τ >45 ms
ms
No
Yes
Select application on next page

10. Selection of circuit breakers






Section 7.3
Capacitor banks
Controlled switching
No
Yes
Energize? Deenergize? Both?
C1 or C2
C1 = Low probability of restrike
C2 = Very low probability of restrike
Type and routine tests
As per IEC?
No
Yes
Basic circuit breaker specification ready


Section 7.4
Reactor banks
Controlled switching?
No
Yes
Energize? Deenergize? Both?
C1 or C2?
Type and routine tests?
As per IEC?
No
Yes
Basic circuit breaker specification ready

Contact us

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